Maine Public Utilities Commission

2006 Annual Report on Electric Restructuring

Presented to the
Utilities and Energy Committee
December 31, 2006

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Presented to the Utilities and Energy Committee of the Maine Legislature

I. Introduction

During its 1997 session, the Legislature enacted P.L. 1997 (the Restructuring Act), ch. 306, codified at 35-A M.R.S.A. §3201-3217, which directed comprehensive restructuring of Maine's electric utility industry, including divestiture of supply assets and functions from the regulated utilities, moving, instead, to a competitive market regime for these services. Since March 1, 2000, Maine utilities have been transmission and distribution (T&D or delivery) companies only and, with limited exceptions, all Maine consumers have had the right to purchase electricity supply in the market. In addition to overseeing regulated utilities, pursuant to the Restructuring Act the Commission also oversees Maine's retail electricity market, procures standard offer service, and participates in regional wholesale market activities that affect Maine's electricity consumers.

Pursuant to the Restructuring Act, the Commission submits this report to the Legislature's Joint Standing Committee on Utilities and Energy describing issues and events related to the Act for the year 2006.

Key Events and Issues

- Wholesale electricity prices declined during 2006 relative to fourth quarter 2005, following similar trends in natural gas markets.

- At the New England regional market level, measures adverse to Maine consumers continued to be pursued, approved by federal regulators and implemented despite the Commission's strenuous opposition.

- In response to Legislative direction, the Commission (1) initiated a rulemaking to govern the acquisition of long-term capacity resources to mitigate consumer costs in the face of regional capacity rules and (2) conducted a study to examine potential alternatives to continued participation in ISO-NE.

- In Maine's retail market, large and medium sized commercial and industrial customers maintained a reasonable and steady level of migration to the retail supply market, while virtually all residential and small commercial customers continued to receive standard offer service.

- The number of retail suppliers serving Maine customers was stable, with several companies supplying load during 2006. However, a large share of the retail market continued to be served by a single set of affiliated suppliers.

- The northern Maine market continued to be served by a single company supplying all standard offer and non-standard offer loads during 2006. Upon soliciting standard offer bids in the northern Maine market for Maine Public Service Company (MPS) customers and receiving bids from only that supplier, the Commission found the lack of competition to be unacceptable, rejected the bids, directed MPS to provide standard offer service for an interim period, and opened a proceeding to consider options for this region.

- The Commission conducted six standard offer solicitations during 2006, including a solicitation seeking demand-side and efficiency measures.

- In partnership with an incumbent standard offer supplier, Constellation Energy, the Commission implemented the “Save-a-Watt 10% Challenge” during winter 2005/2006, pursuant to which Constellation contributed $415,000 to efficiency programs for Maine residential and small commercial customers.

- Retail stranded cost and distribution rates remained relative flat for CMP and BHE, although transmission rates increased, in large part because of socialized transmission investment in other parts of the region.

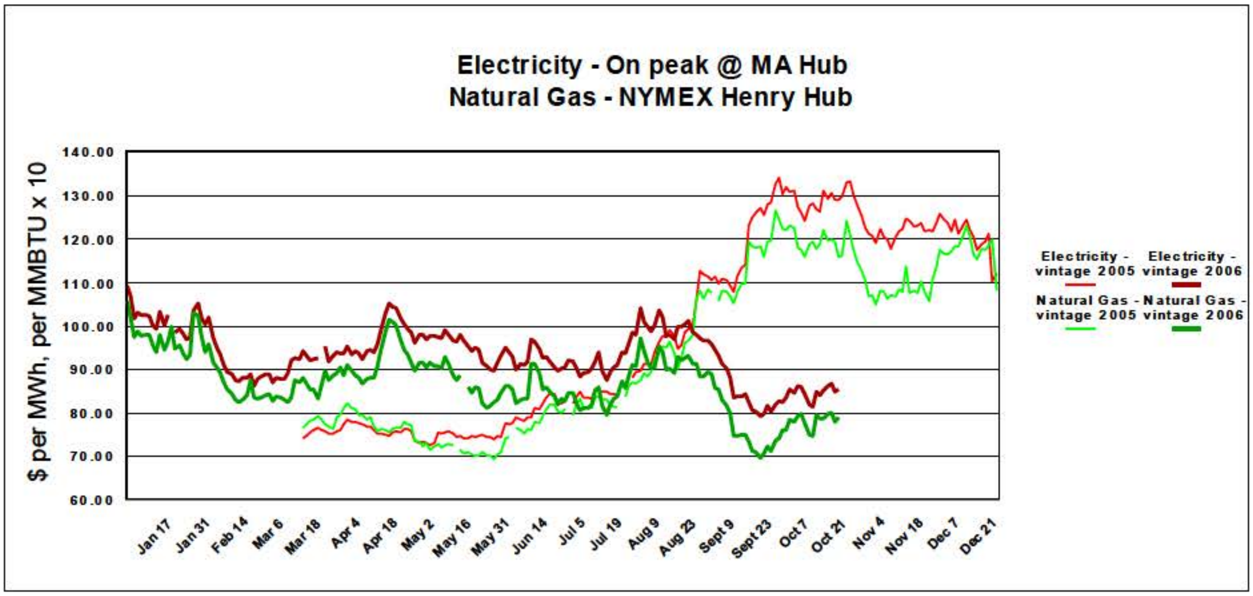
II. REGIONAL WHOLESALE MARKET AND RELATED ACTIVITY

With the restructuring of the electricity market, Maine became part of a broader regional market for wholesale electricity. In recognition of this, in 1997 the Legislature enacted 35-A MRSA §3215, which directs the Commission to participate in regional and national activities to protect “the interests of competition, consumers of electricity, or economic development of the state.”

The New England System Operator (ISO-NE) has been the Regional Transmission Organization (RTO) for New England since February 1, 2005. As the RTO, ISO-NE is responsible for the day-to-day operation of the regional grid as well as for administering the regional markets pursuant to a set of tariffs and rules approved by the Federal Energy Regulatory Commission (FERC). The Commission participates actively in tariff and market rule development processes, and also intervenes and takes positions at FERC on matters affecting the competitiveness of the wholesale electric markets, reliability, and prices paid by Maine electricity consumers.

Market Prices

Wholesale electric energy prices declined during 2006, driven by declines in natural gas and oil prices. As shown on the graph below, by the fourth quarter of 2006, wholesale prices had declined by about 30% compared to fourth quarter 2005. However, even with these declines, wholesale electricity prices remain substantially above 2003 and 2004 levels.



Major Cases at FERC and Other Federal Initiatives

There has been a trend over the past year toward pushing the development of new generating and transmission resources in the region. The details are discussed more fully in the following sections. This trend raises important questions for Maine regarding where these new facilities will be sited, how they will affect the market price of electricity in Maine, and how their costs will be allocated.

Forward Capacity Market (FCM) Settlement

On June 15, 2006, FERC approved a contested settlement that establishes a capacity market and sets a schedule of payments to generators over a four-year transition period beginning December 2006. The case that resulted in the FCM settlement began with a dispute over the level of compensation to which generators would be entitled when their units were required to serve in the southwestern Connecticut load pocket. In ruling on the dispute the FERC directed ISO New England to establish a mechanism that appropriately valued and compensated New England capacity based on where the capacity was located. FERC wanted the mechanism to address the need for more generation in the southwestern Connecticut and northeastern Massachusetts load pockets, recognizing that Maine's surplus of generation resources could not always be exported from Maine due to transmission limitation.

ISO-NE filed a proposal, known as LICAP (Locational Installed Capacity) that would have sharply increased costs for all of the New England states without requiring new generation to be built, even in those southern New England locations where it was needed. Maine, as well as every other New England state opposed the LICAP proposal. After a hearing, FERC directed the parties to engage in settlement negotiations.

The Commission worked with other states and energy companies to come up with a compromise but ultimately rejected the settlement because of its impact on Maine consumers. The Commission supported the long-term market proposal which it helped to develop as part of the settlement. This long term market proposal, if properly implemented, would allow for a competitive market for new resources, including conservation and demand response resources.

However, the settlement also included transition payments for a period of time beginning in 2006. The Commission strongly opposed the transition rates approved by FERC. FERC's approval of the settlement is expected to result in rate increases of about 6% for Maine's residential electric consumers and 10% for Maine's medium and large commercial and industrial electric consumers over a four-year period. FERC rejected the Commission's argument that given Maine's capacity surplus, the rate increases had not been justified for Maine consumers. The Commission will seek court review of FERC's decision.

Installed Capacity (IC) Requirements

Another important case at FERC during 2006 involves the determination of how much capacity is needed within a 12- month period to ensure reliability. One of the most significant issues to arise in this case is whether states or the FERC should determine the appropriate level of reliability. Although the FERC has for many years set the IC requirement, the determination of what level of resource adequacy is required is a matter in which states must play a major role, since ultimately retail consumers will pay the cost of increased levels of reliability. FERC's decision that it has sole authority to establish the IC requirement is being challenged in federal court. The Commission has intervened in this appeal as part of the New England Conference of Public Utility Commissions (NECPUC) and individually.

Request for Increased Return on Equity (ROE).

On November 4, 2003, a group of New England transmission owners filed a request for approval for a significant increase in the return on common equity component of the regional and local transmission rates under the ISO-NE open access transmission tariff. The Commission took a lead role in developing NECPUC comments protesting the proposed increase. On October 31, 2006, FERC issued a decision in this case (over a year after the presiding judge issued her initial decision). FERC approved a lower rate than requested by the New England transmission owners but rejected a portion of the presiding judge's recommendation, instead approving the transmission owners' request for an ROE adder for new transmission construction. The Commission, individually and as part of NECPUC, municipal utilities and other consumers had strongly objected to the new transmission adder and may seek rehearing at FERC.

Energy Policy Act of 2005

The Energy Policy Act of 2005 ("EPAct 2005") triggered two related proceedings that may affect Maine consumers. First, EPAct required the Department of Energy ("DOE") to undertake a nationwide study of electric transmission congestion by August 7, 2006, and every three years thereafter. Following the issuance of the congestion study, EPAct authorizes DOE to designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a National Interest Electric Transmission Corridor ("NIETC"). Of crucial significance, the consequence of an NIETC designation is that EPAct gives FERC backstop siting authority over a transmission project even when the state commission finds that it is not in the public interest or the project would violate local or state environmental regulations or laws. This means that if a state either rejects or fails to approve within a year a transmission project that is within a national corridor, FERC may override the state siting authorities and grant a permit for the siting of the line.

As a result of these EPAct 2005 provisions, DOE issued a congestion study in August 2006 and requested comments on the study. DOE categorized broad areas experiencing congestion into one of three categories which denoted DOE's evaluation of the severity of congestion within the broad area. The categories identified by DOE were: critical congestion area, congestion area of concern, and conditional congestion area. New England was designated a congestion area of concern and Maine was identified as a potential target of federal preemption. The DOE indicated in its request for comments on the study and on possible designation of corridors that it might designate corridors in areas that fell into any of the three categories.

The Commission filed comments both individually and as part of NECPUC and the National Association of Regulatory Commissioners ("NARUC") strongly opposing the designation of corridors based on the DOE congestion study. The comments underscored the deficiencies of the congestion study, the lack of the requisite consultation with the affected states, and in New England the lack of any evidence that the state siting process had prevented the construction of any transmission project recommended by ISO-NE. On November 10, 2006, DOE decided that it would issue draft designations and provide an opportunity for additional comment before final NIETC designations are made. The Commission will continue to be actively involved in this proceeding.

The second proceeding is the FERC rulemaking governing its backstop siting authority. On June 16, 2006 FERC issued its proposed rule to implement its backstop siting authority under EPAct 2005. Through NARUC, the Commission developed comments on the proposed rule. The comments address deficiencies in the proposed rule and provide proposals for addressing these deficiencies. The Commission will continue its participation in this proceeding.

State Legislative Initiatives

The Resolve

In response to the developments discussed above, in particular the significant cost increases that will result from the FCM settlement, during its 2006 session the Legislature enacted a Resolve, To Direct the Public Utilities Commission to Examine Continued Participation by Transmission and Distribution Utilities in this State in the New England Regional Transmission Organization. Pursuant to the Resolve, the Commission opened an inquiry on June 29, 2006 to produce findings and recommendations to the Utilities and Energy Committee of the Legislature regarding the costs and benefits of CMP and BHE continuing to participate in the New England RTO. The Commission has received comments on the scope of the inquiry and Commission staff has issued two draft sections for comment. These sections explore current costs of remaining part of the New England RTO and the legal implications of CMP and BHE withdrawing from the RTO.

The Commission will provide preliminary findings to the Utilities and Energy Committee in January 2007 as required by the Resolve.

Energy Act

At least in part because of concerns about the regional market, during its 2006 session the Legislature enacted an Act To Enhance Maine's Energy Independence and Security (Energy Act). P.L. 2005, ch. 677. Part B of the Energy Act provides the Commission with the authority to incorporate cost-effective demand response and energy efficiency (collectively "demand-side resources") into standard offer supply and explicitly recognizes the Commission's authority to consider standard offer supply arrangements of varying lengths and terms. To address the cost of regional capacity requirements and to ensure grid reliability, Part C of the Energy Act authorizes the Commission to direct large investor owned utilities to enter into long-term contracts for capacity resources and requires the Commission to develop a long-term plan for electric resource adequacy. The Act requires that the Commission adopt the standards and procedures governing long-term contracting and establish the resource plan through major substantive rulemaking procedures.

To gather the input of interested parties on the implementation of the Energy Act, the Commission solicited public comment through a Notice of Inquiry (Docket No. 2006-314, issued June 7, 2006), and a Request for Comments (Docket No. 2006-411, issued July 26, 2006). In response, the Commission received a large number of comments expressing varying viewpoints on how the Commission should proceed to implement the provisions of the Energy Act.

In response to the standard offer provisions of the Energy Act, on October 20, 2006, the Commission solicited bids for terms of one, three, six and nine years for the residential and small commercial classes in the Central Maine Power Company and

Bangor Hydro-Electric service territories. The RFP sought bundled demand/supply bids as well as supply-only bids. Initial proposals were received in mid-November and negotiations are ongoing.

To implement the long-term contract and resource adequacy plan portions of the Act, the Commission, on October 3, 2006, issued a Notice of Rulemaking and proposed rule for public comment. The Commission will adopt provisional rules and, pursuant to the major substantive rulemaking requirements, will submit them to the Legislature for review and approval.

III. MAINE RETAIL MARKET

During 2006, the retail market in most of Maine continued to exhibit a reasonable level of competitive activity in the medium and large commercial and industrial (C&I) customer sectors, although a set of affiliated companies continued to have a large market share. The retail market continued to provide few if any options to standard offer service for residential and small commercial customers, although competition for the standard offer loads of small customers remained robust.

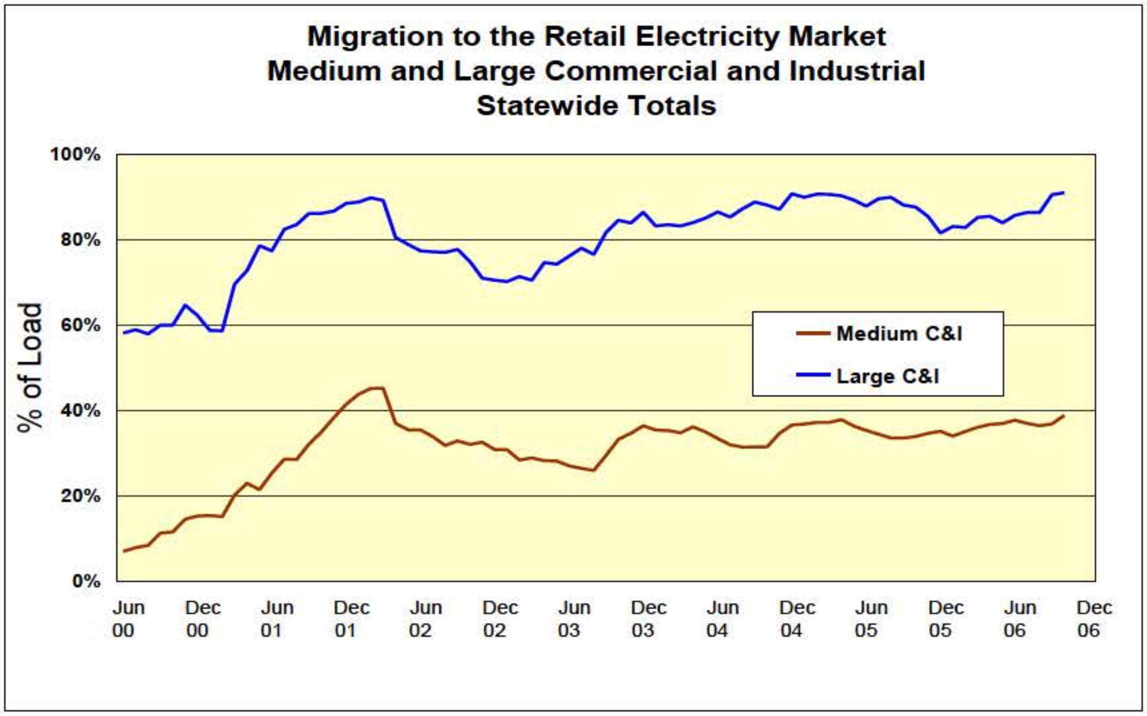
Sixteen retail providers were licensed in 2006, bringing the number of licensed providers in Maine to seventy-six. Many of these, however, are not active in the market. A complete list of licensed suppliers is available at http://www.maine.gov/mpuc/industries/electricity/ElectricSupplier/ceplist.htm

Medium and Large C&I Sectors

Since the beginning of restructuring, many medium and large C&I customers have acquired supply directly in the retail market. Terms of service and prices are negotiated directly between customers and suppliers, or, in some cases, with the assistance of aggregators or brokers. Depending upon customer preference and supplier product offerings, prices may be fixed for multi-year terms, or, at the other end of the spectrum, prices may change hourly in accordance with real time or near real time wholesale markets. [1]

Although migration to and from the competitive market is influenced to some extent by the relationship between standard offer and non-standard offer prices, the prevailing trend is for customers to remain in the market once they have left the standard offer. The graph below shows migration among medium and large customers, and reflects the overall trend toward migration to the open market.

[1] Because an increasing number of customers began selecting real-time and other forms of indexed pricing, during 2006 the Commission adopted a rule requiring suppliers to disclose the risks of these products to potential customers.



Residential and Small Commercial Sectors

There is little retail market activity in these small customer sectors in Maine or other states. However, because Maine's standard offer providers are chosen through competitive bidding, residential and small commercial customers are receiving competitively-procured supply, albeit at the bulk level.

During 2006 "green" products, featuring hydroelectric, biomass, wind, low-impact hydro generation, and "green tags" continued to be available through residential and public sector aggregation groups. The Maine Green Power Connection provided information regarding green power, and the State Energy Program provided modest funding for information outreach.

Northern Maine

Competition in northern Maine continued to be weak during 2006. The small size of the market, coupled with its dis-integration from New England and the lack of competition in New Brunswick, has hindered market development here since retail access began in 2000.

During 2006 only one retail supplier, served load in northern Maine. In September 2006, after issuing an RFP for standard offer service for the MPS service territory and receiving bids from only one supplier, the Commission found the lack of competition to be unacceptable, rejected the bids and directed MPS to supply standard offer service for an interim period. Simultaneously, the Commission also opened a proceeding to consider options for northern Maine and expects to bring recommendations to the Legislature during the 2007 session.

IV. STANDARD OFFER SERVICE

Overview of 2006

During 2006, the portion of Maine's electric load that receives standard offer service remained steady at about 60%. By customer class, standard offer service supplies about 65% of the load of Medium C&I customers and 10% of the load of Large C&I customers in Maine. Standard offer service continues to supply virtually all residential and small commercial customers, as has been the case since retail access began.

The standard offer suppliers during 2006 and the prices they charge are set forth below. The prices shown here are averages; actual prices for the medium class may vary by month and for the large class by month and time of day. For more detailed prices, please see the Commission's web page at http://www.state.me.us/mpuc/new%20standard%20offer/standard_offer_rates.htm.

Average Standard Offer Prices in 2006

	Residential/Small Commercial		Medium C&I		Large C&I	
	Price ¢/kWh	Supplier(s)	Price ¢/kWh	Supplier(s)	Price ¢/kWh	Supplier(s)
CMP						
Jan-Feb	6.95	CPS Maine	10.05	Independence	10.0	Suez
Mar-Apr	8.38	Constellation	9.54	FPL, Dominion	10.18	Constellation
Sept-Dec	8.38	Constellation	10.0	FPL, Dominion	10.15	BP
BHE						
Jan-Feb	7.14	Select, Independence	10.2	FPL	9.6	Suez
Mar-Apr	8.71	Constellation	9.78	FPL	9.82	Constellation
Sept-Dec	8.71	Constellation	10.2	FPL	9.79	BP
MPS						
Jan-Dec	5.46	WPS	5.81	WPS	6.4	WPS

Procurement Processes

CMP and BHE Residential and Small Commercial

The Commission continued to procure standard offer supply in accordance with the hedging program it began in 2005. The process began with the release of RFPs in September 2004 to initiate a "laddering" structure whereby the Commission would secure portions of the required supply at different times, thereby reducing retail customer exposure to the volatility of the wholesale market. Specifically, bids were requested for one-third load segments for terms of one, two and three years, thereby setting up for subsequent procurement of one-third segments annually as the initial terms expired.

For the March 2006 term one-third segment, the Commission issued RFPs in September 2005. Upon receiving and evaluating final binding bids in December 2005, the Commission designated Constellation Energy Commodities Group-Maine, LLC as the standard offer provider for the CMP and BHE loads. Although the bid prices for this one-third segment were high (11.8 cents/kWh for CMP and 12.2 cents/kWh for BHE), reflecting prevailing market conditions at the time, the fact that two-thirds of the load continued to be served with previously procured supply and lower prices mitigated the effect on consumers. The resulting prices on March 1, 2006 were 8.4 cents/kWh and 8.7 cents/kWh for CMP and BHE, respectively.

In October 2006 the Commission issued an RFP for the March 2007 term. Pursuant to recently-granted Legislative authority, the Commission sought proposals that bundled demand and supply resources into standard offer service. Initial proposals were received in mid-November and negotiations are ongoing.

CMP and BHE Medium and Large C&I

The Commission completed two solicitations for medium and large class standard offer service during 2006, and began a third in late 2006 for the term beginning March 1, 2007.

On December 8, 2005, the Commission issued RFPs for standard offer service for the CMP and BHE medium and large classes for the six-month term beginning March 2006. Suppliers submitted indicative bid prices in January 2006 and after negotiating negotiated and resolved non-price terms with Commission staff and utilities, suppliers submitted final binding bids later that month. After evaluating the final proposals, the Commission designated suppliers and prices as follows:

Class	Supplier	Average Price (cents/kWh)
CMP Medium	FPL 80%/ Dominion 20%	9.54
CMP Large	Constellation	10.18
BHE Medium	FPL	9.78
BHE Large	Constellation	9.82

The solicitation for CMP and BHE medium and large classes for the September 2006 term began when the Commission issued RFPs in early June 2006. After receiving indicative bids, negotiating contract and other non-price terms, and receiving final bids, the Commission designated suppliers and prices as follows:

Class	Supplier	Average Price (cents/kWh)
CMP Medium	FPL 80%/ Dominion 20%	10.04
CMP Large	BP	10.15
BHE Medium	FPL	10.19
BHE Large	BP	9.80

MPS – All Classes

As noted above, the market in this area of Maine has been weak for some time. In September 2006, the Commission issued an RFP seeking standard offer service for all MPS customer classes. Because only one retail supplier bid, the Commission found the lack of competition to be unacceptable, rejected the bids and ordered MPS to supply standard offer service for an interim period, thereby allowing the Commission and the Legislature the opportunity to consider options for northern Maine.

Winter 2005/2006 Memorandum of Understanding (MOU)

In response to anticipated supply shortages and high prices during the winter 2005/2006 in the wake of Hurricanes Katrina and Rita, the Commission negotiated an MOU with an incumbent standard offer supplier, Constellation Energy Commodities Group, Inc., pursuant to which Constellation would provide financial support for stepped-up conservation efforts and incentives. In particular, the Commission expanded the Efficiency Maine residential lighting program and implemented a new program designed to give customers incentives to conserve during the winter. The new program, called "The Save-a-Watt 10% Challenge", permitted eligible CMP and BHE residential and small commercial customers to enter drawings to win a $1,000 appliance rebate toward the purchase of a qualified ENERGY STAR appliance. Constellation contributed $415,000 toward these programs.

Other key elements of these conservation efforts are summarized below:

- During the winter period, 52% of CMP and BHE residential/small commercial customers reduced usage by an average of 22% (148 million kWh) compared to last season.
- Of that, 118 million kWh, or 80%, were saved by customers who qualified for the Save-A-Watt 10% Challenge.

- About 150,000 customers (28%) qualified for Save-A-Watt each month by reducing usage by 10% or more. On average, these customers reduced usage by 28%.

- Over the course of the winter, the Commission randomly selected 50 winners in the Save-A-Watt 10% Challenge and awarded each a $1,000 rebate toward the purchase of an ENERGY STAR qualified product.

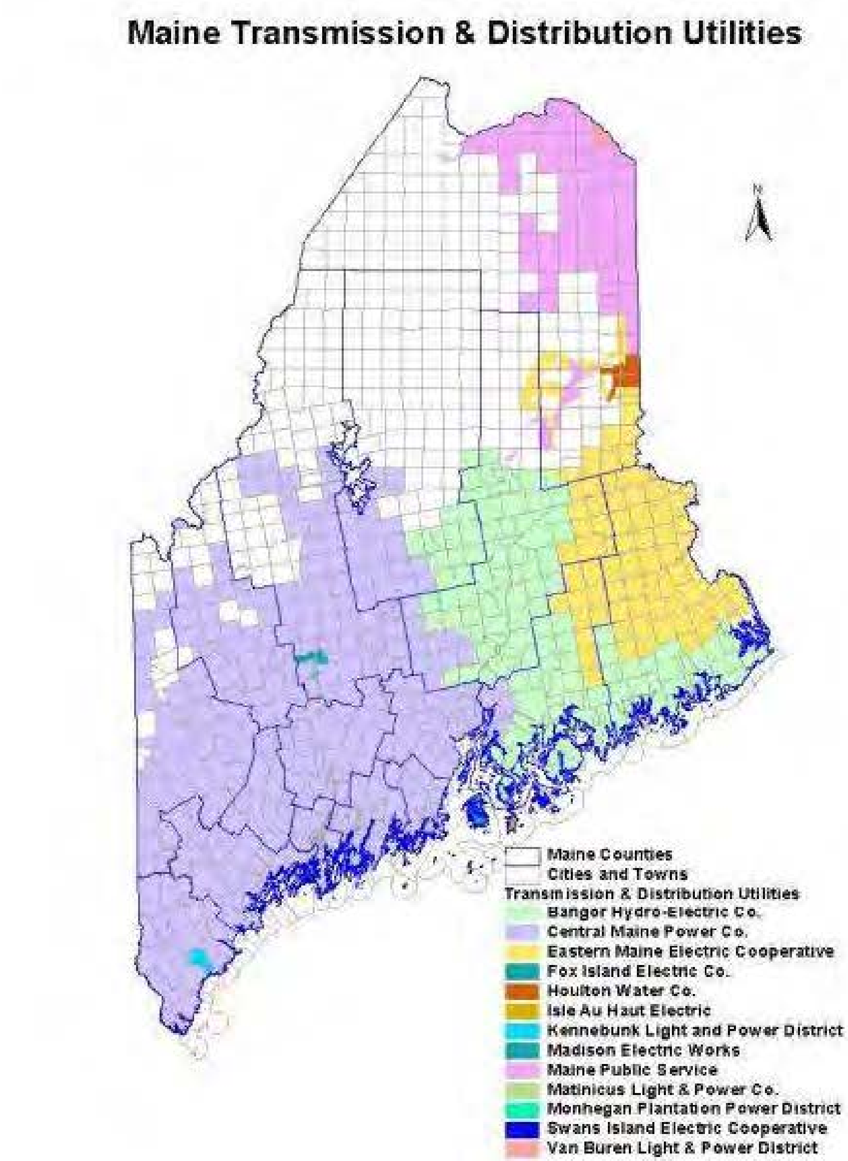
- Through the PUC's Efficiency Maine program, the Residential Efficient Lighting Rebate program was expanded. This included developing and running ads twice weekly in major daily newspapers, including ads that provided cut-out coupons.

- From November through March, 223,188 light bulb rebate coupons were redeemed at a value of $2 per coupon for a total of $446,376.

V. DELIVERY SERVICES AND PRICES

There are thirteen electric or transmission and distribution (T&D) utilities in Maine – three investor-owned (IOU) and ten consumer owned (COU). The three IOU's serve most of the State, and among them Central Maine Power (CMP) is the largest, serving about 80% of all Maine's load in 2006. BHE and MPS served most of the remaining load, with the COUs serving, in the aggregate, a few percent.

The map below shows the geographic areas each utility serves:



The table below provides a summary of residential electricity sales and rates by utility.

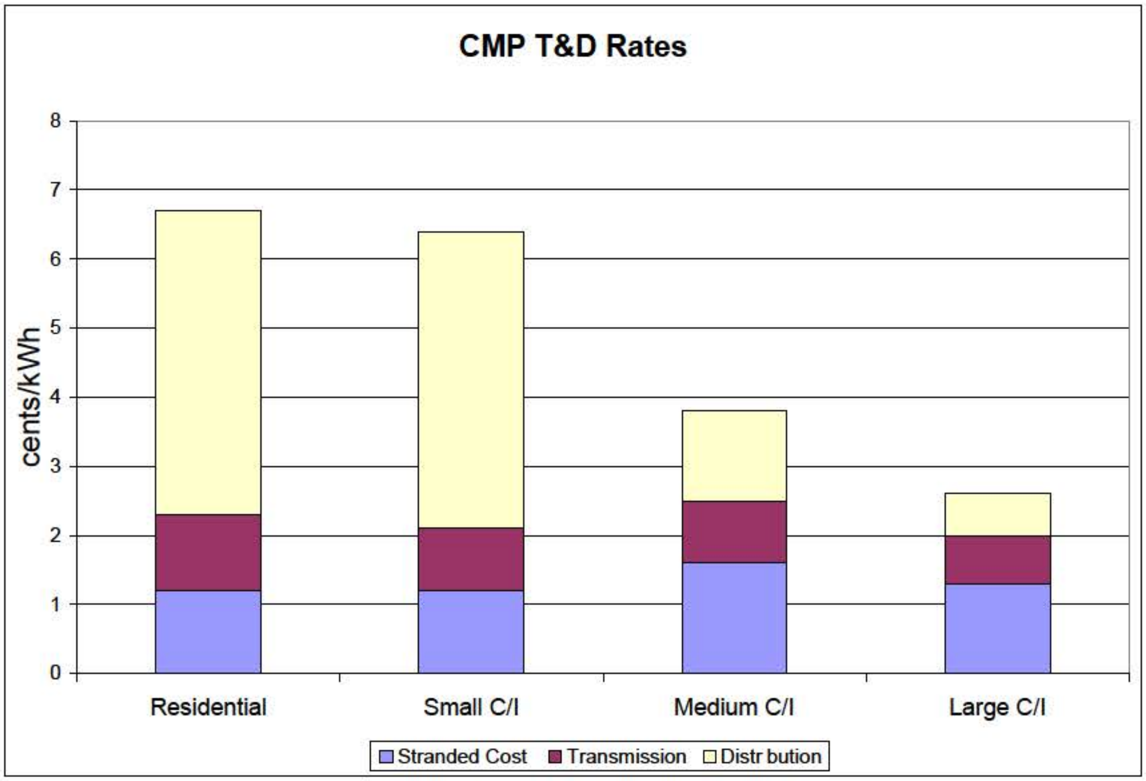
RESIDENTIAL RATES IN MAINE

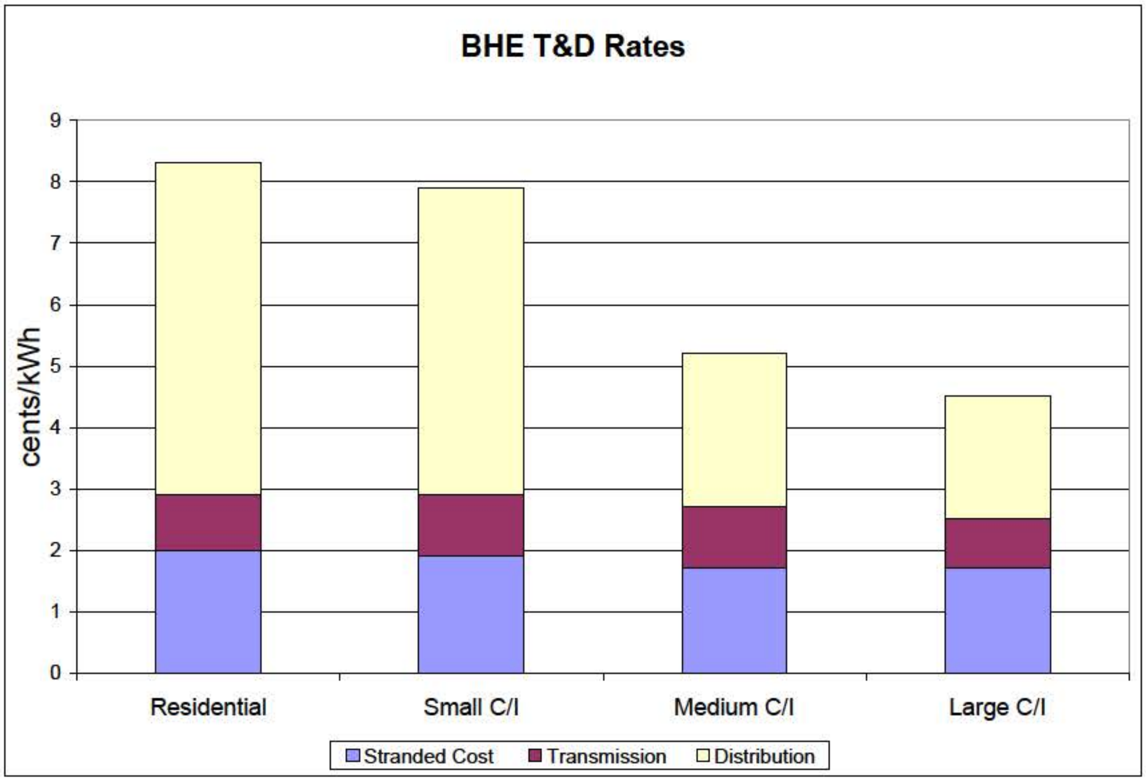
(As of Q4 2006)

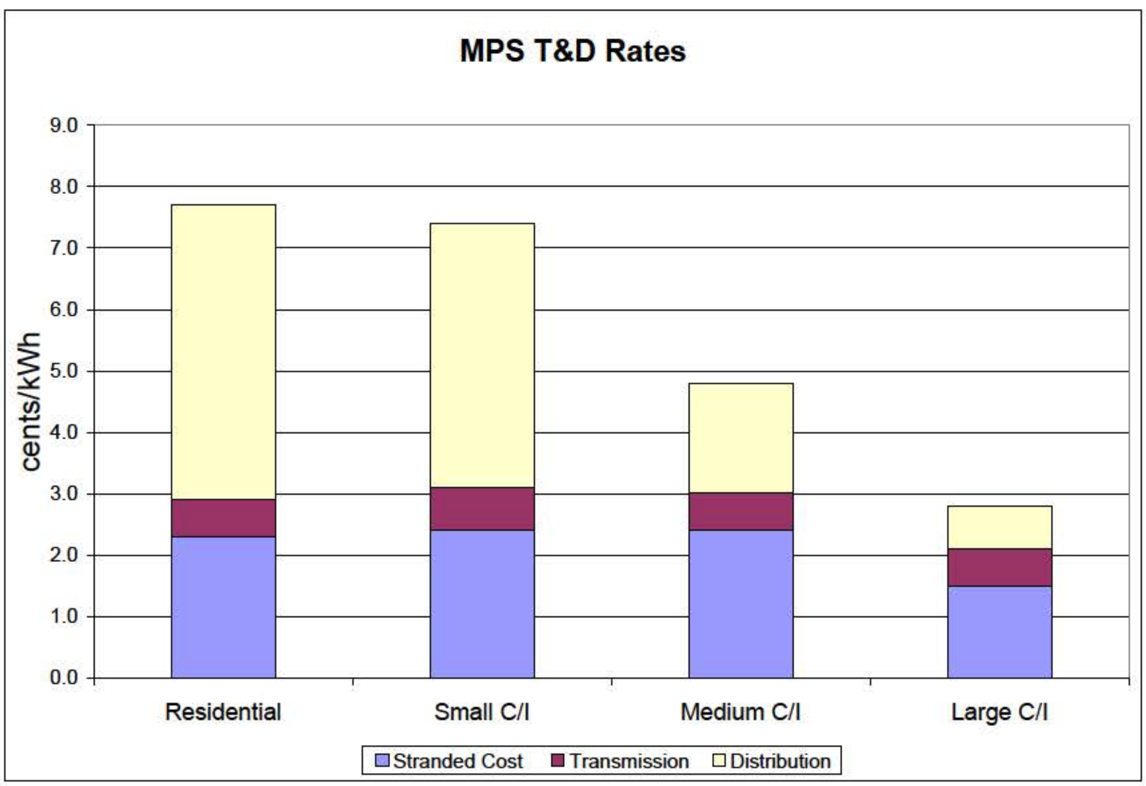
	% of State Residential Load	kWh	T&D Delivery Rate ¢/kWh	Standard Offer Rate ¢/kWh	Total Rate ¢/kWh
INVESTOR-OWNED UTILITIES					
CMP	79.6%	3,502,355,270	6.56	8.38	14.94
BHE	13.6%	598,648,495	8.52	8.71	17.23
MPS	4.2%	183,229,422	7.75	5.46	13.21
COOPERATIVES & MUNICIPAL-OWNED UTILITIES					
EMEC	1.2%	52,643,499	7.63	5.80	13.43
Houlton	0.6%	27,819,402	3.16	5.37	8.53
Van Buren	0.2%	7,349,986	2.77	6.60	9.37
KL & P	0.0%			10.50	*NA*
MEW	0.4%	16,967,236	4.30	4.57	8.87
Matinicus	0.0%	278,959	Exempt from Standard Offer requirements		43.50
Monhegan	0.0%	294,700	Exempt from Standard Offer requirements		55.87
Fox Island	0.1%	5,990,288	18.89	12.65	31.54
Isle au Haut	0.0%		Exempt from Standard Offer requirements		*NA*
Swans Island	0.1%	2,360,330	16.33	10.00	26.33
STATE TOTAL/ AVERAGE		4,397,937,587	6.87	8.24	15.12

T&D delivery rates include three components - transmission, distribution, and stranded costs. Transmission rates cover the cost of constructing and operating the transmission system in Maine, as well as costs allocated to Maine for regional pool transmission facilities (PTF). Transmission rates are regulated by FERC. Distribution rates cover costs incurred by the T&D utility to construct and operate the local distribution system and are regulated by the Commission. Stranded cost rates reflect the net, above-market costs for generation obligations that utilities incurred prior to industry restructuring, and are also regulated by the Commission.

The following charts illustrate T&D rates for CMP, BHE and MPS:




BHE T&D Rates
cents/kWh
0
1
2
3
4
5
6
7
8
9
Residential
Small C/I
Medium C/I
Large C/I
Stranded Cost
Transmission
Distribution


MPS T&D Rates
cents/kWh
0.0
1.0
2.0
3.0
4.0
5.0
6.0
7.0
8.0
9.0
Residential
Small C/I
Medium C/I
Large C/I
Stranded Cost
Transmission
Distribution

Distribution

As shown above, distribution rates vary by utility and customer class. For example, residential customers typically pay more than industrial customers to reflect differences in the underlying costs to serve them, such as the fact that residential customers take service at the distribution system level while many industrial customers take service directly at the high voltage, transmission system level. During 2006, distribution rates for CMP and BHE were stable, although distribution rates for MPS increased by 10.6% pursuant to a stipulation approved by the Commission in Docket 2006-24.

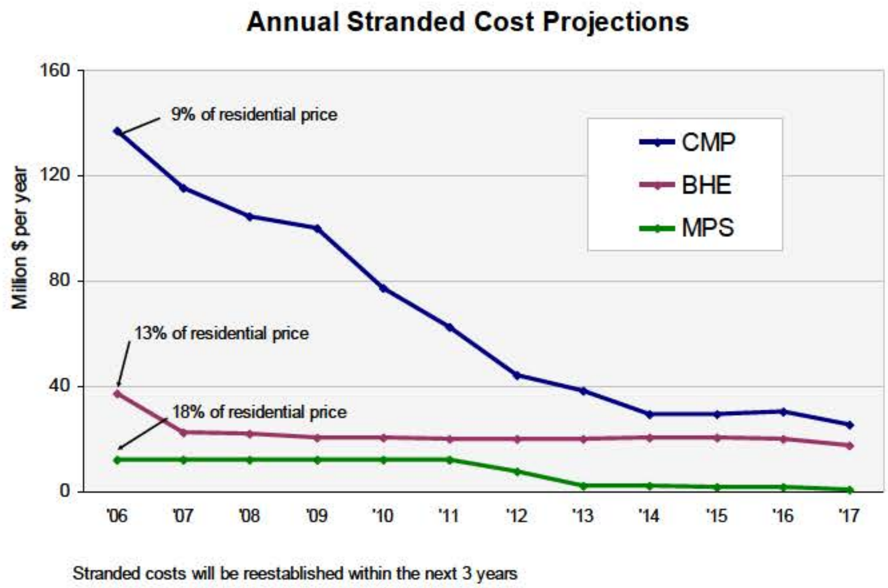
Transmission

Transmission rates increased during 2006, primarily as a result of the regional allocation of Pool Transmission Facilities (PTF). In particular, the amounts Maine consumers are paying for new and upgraded transmission in southern New England increased in 2006 – a trend which is likely to continue.

Stranded Costs

The Restructuring Act allows CMP, BHE and MPS to recover stranded costs in the rates they charge for delivery service. Stranded costs reflect the net, above-market costs for generation obligations that utilities incurred prior to industry restructuring. For example, stranded costs include the difference between payments the utilities must make pursuant to pre-existing purchased power contracts, primarily with qualifying facilities (QFs) and the current market value of that power. Stranded cost rates are re-set for CMP, BHE and MPS every two to three years, typically to coincide with the sale terms of the utilities' QF entitlements and may also be reconciled annually to capture difference between projected and actual expenses and revenues.

As shown below, over time stranded costs will decline to zero. The most significant changes in stranded costs occur when utilities' QF contracts expire.



VI. MAINE ELECTRICITY SUPPLY RESOURCES

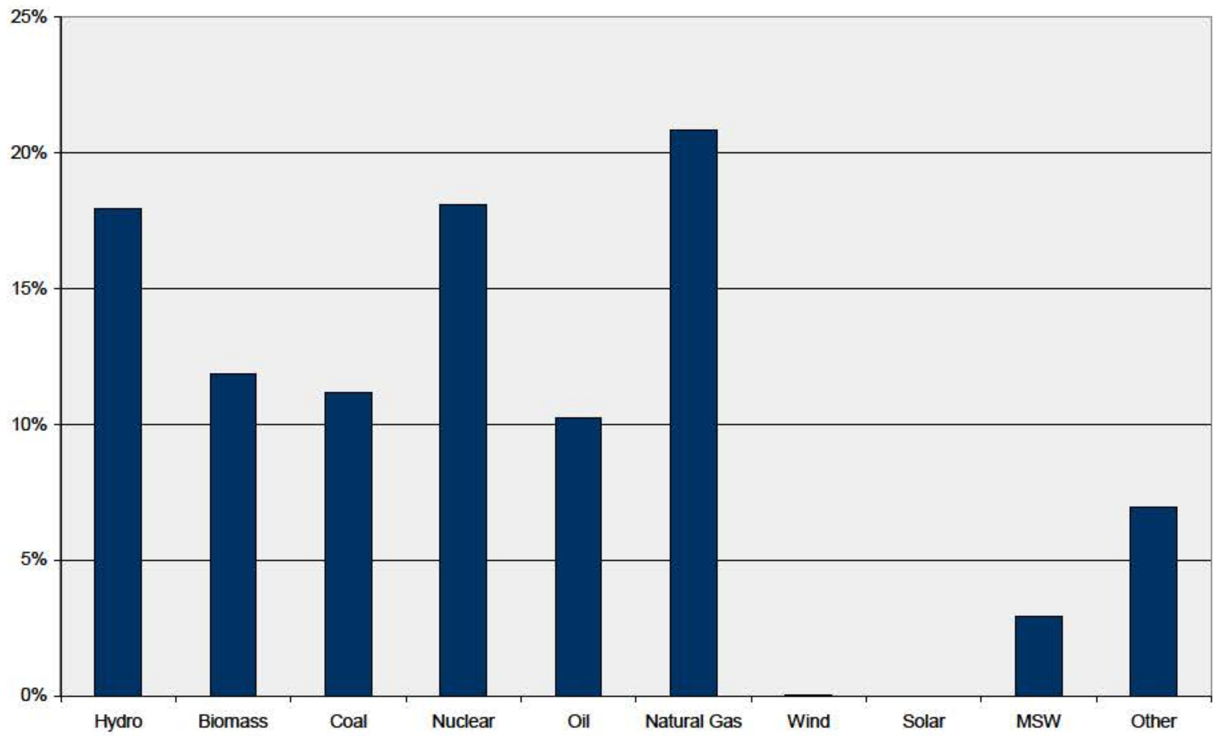
Resources Serving Maine Customers

The Restructuring Act establishes a 30% resource portfolio standard (RPS) that requires electricity suppliers (including standard offer suppliers) to supply 30% of their Maine load from "eligible resources." The Act defines eligible resources to be generating units whose capacity does not exceed 100 megawatts and that produce electricity from tidal, fuel cells, solar, wind, geothermal, hydroelectric, biomass, or municipal solid waste in conjunction with recycling, that qualify as small power producers under federal regulations, or that are efficient cogeneration units.

As shown in the chart below, during 2005,[2] approximately 33% of Maine's load was supplied by eligible resources. Virtually all eligible supply was provided by hydro, biomass, or MSW, with a small fraction provided by eligible fossil fuels, wind, or solar.

[2] The Commission will receive information about suppliers' 2006 resource mix when suppliers file their annual reports in June 2007.

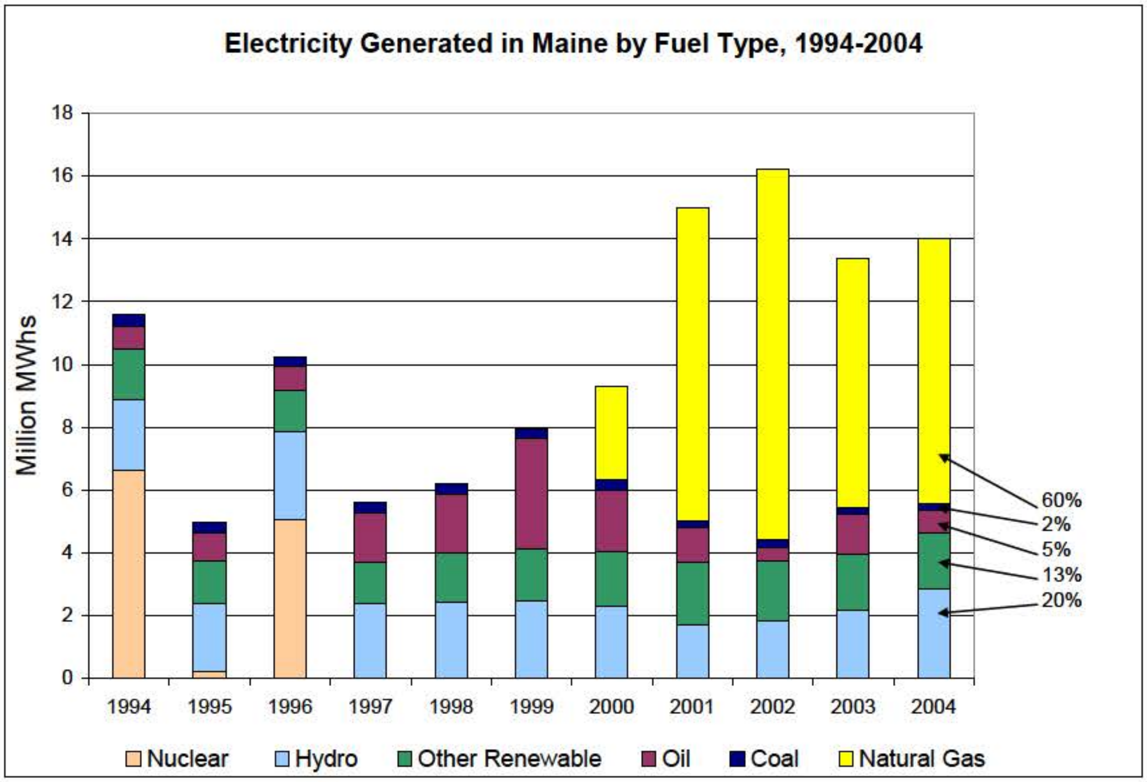
Resources Serving Maine's Electricity Customers in 2005



The generation that fulfills the 30% RPS may come from a variety of locations. The generation that suppliers assign to load in Maine may be generated in Maine, in another New England state, in Canada, or (less frequently) in the Middle Atlantic states. Since 2002, competitive providers in the ISO-NE territory have operated under a "tradable attribute" certificate system known as the Generation Information System (GIS). The GIS allows suppliers to trade electricity attributes (e.g., fuel source and emissions levels) separately from the energy commodity. Suppliers in the ISO-NE area demonstrate compliance with Maine's 30% RPS through GIS certificates. This process reduces supplier compliance costs and allows for accurate verification.

Electricity Generated in Maine

In recent years, five electric generating plants fueled by natural gas have been built in Maine. This phenomenon is the result of both electric restructuring and the completion of new natural gas transmission facilities within the State. Publicly available information summarizes the resources used in each state to generate electricity (which may in turn be sold in other states), and shows the shift in Maine's generation mix over time. At this time, generation data is not available beyond 2004.



Uniform Disclosure Labels

The Restructuring Act directs the Commission to ensure that comparative information regarding electricity supply is disseminated to customers. The Commission implemented this directive by designing a uniform information disclosure label that contains a supplier's resource mix and emissions information. Residential and small commercial customer suppliers must provide a disclosure label to their customers quarterly, and suppliers to larger customers must provide the label upon request. Labels for standard offer providers may be found on the Commission's web page at:

http://www.maine.gov/mpuc/industries/electricity/standard_offer/disclosure_labels_history.html

Voluntary Renewable R&D Fund

The Restructuring Act directs the Commission to establish a program to allow electricity customers to make voluntary contributions to fund renewable resource research, development, and demonstration projects. To date, customers have donated approximately $250,000 through one-time or monthly contributions through their electricity bills. In 2004, the fund provided support for a Chewonki Foundation and Hydrogen Energy Center project to develop an energy system using hydrogen generators, storage, and fuel cells.

Pursuant to the Act, the State Planning Office (SPO) is responsible for administering this program. During 2006, however, SPO agreed that responsibility should logically reside with the Commission, which also administers other, similar programs. The Commission plans to propose this statutory change to the Legislature during this session.

VII. AFFILIATED COMPETITIVE PROVIDERS AND COMPLIANCE COSTS

The Restructuring Act requires T&D utilities and their marketing affiliates to comply with comprehensive standards of conduct and market share limitations. These limitations are intended to prevent utility marketing affiliates from obtaining any undue market advantage by virtue of their corporate relationship with T&D utilities. The Act requires the Commission to determine and report the actual and estimated future costs of implementing these requirements.

During 2006, there were no issues associated with standards of conduct. CMP does not have a marketing affiliate. In 2002, BHE formed a marketing affiliate, Emera Energy Services, Inc. (EES), but EES does not market services in BHE's territory. MPS's marketing affiliate, Energy Atlantic, no longer serves customers in Maine.

VIII. ACTIVITIES IN OTHER STATES

The Restructuring Act directs the Commission to report on activities relating to changes in the regulation of electric utilities in other states. 2006 was a year during which signs of concern, or at least questions, about the merits of restructuring have appeared in some states.

Appendix A includes a report written by Kenneth Rose of the Institute of Public Utilities at Michigan State University and Karl Meeusem of Ohio State University that provides a comprehensive review of state electricity markets during 2006.

Appendix A

2006 Performance Review of Electric Power Markets

Review Conducted for the Virginia State Corporation Commission*

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August 27, 2006

*This report was conducted under contract with the Virginia State Corporation Commission as Part I (of three parts) of the Commission's annual report to the Virginia General Assembly on the advancement of a competitive retail electricity market in the Commonwealth of Virginia. The views expressed here are those of the authors and do not necessarily reflect the views or opinions of the Virginia State Corporation Commission.

Executive Summary

Retail Markets

The overall status of state retail access has remained relatively unchanged for several years. Sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Nevada and Oregon allow retail access for larger customers only. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Twenty-six states are not considering retail access or restructuring at this time and no state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning. A total of 34 states have repealed, delayed, suspended, or limited retail access to just large customers, or are now no longer considering retail access.

At this point, states that have restructured either remain in a transition period or have ended the transition and now have retail prices determined by a market process. To examine state retail market performance, a comparison is made of the retail price trends in restructured and non-restructured states. Figure ES shows the price trends for the states where the transition period has ended for most residential customers in the state by 2005 and where the price residential customers are paying is based on a market process (that is, procurement of power for most residential customers in the state is through bidding, auction, distribution company purchase in the wholesale market, or some other process that secures power for customers that have not selected a supplier). This includes the District of Columbia, Massachusetts, Maine, New Jersey, and New York. Also depicted in the figure is the U.S. average price for residential customers, a combined weighted-average of all states that restructured,[1] and a weighted-average price of the 30 states that remain regulated.[2]

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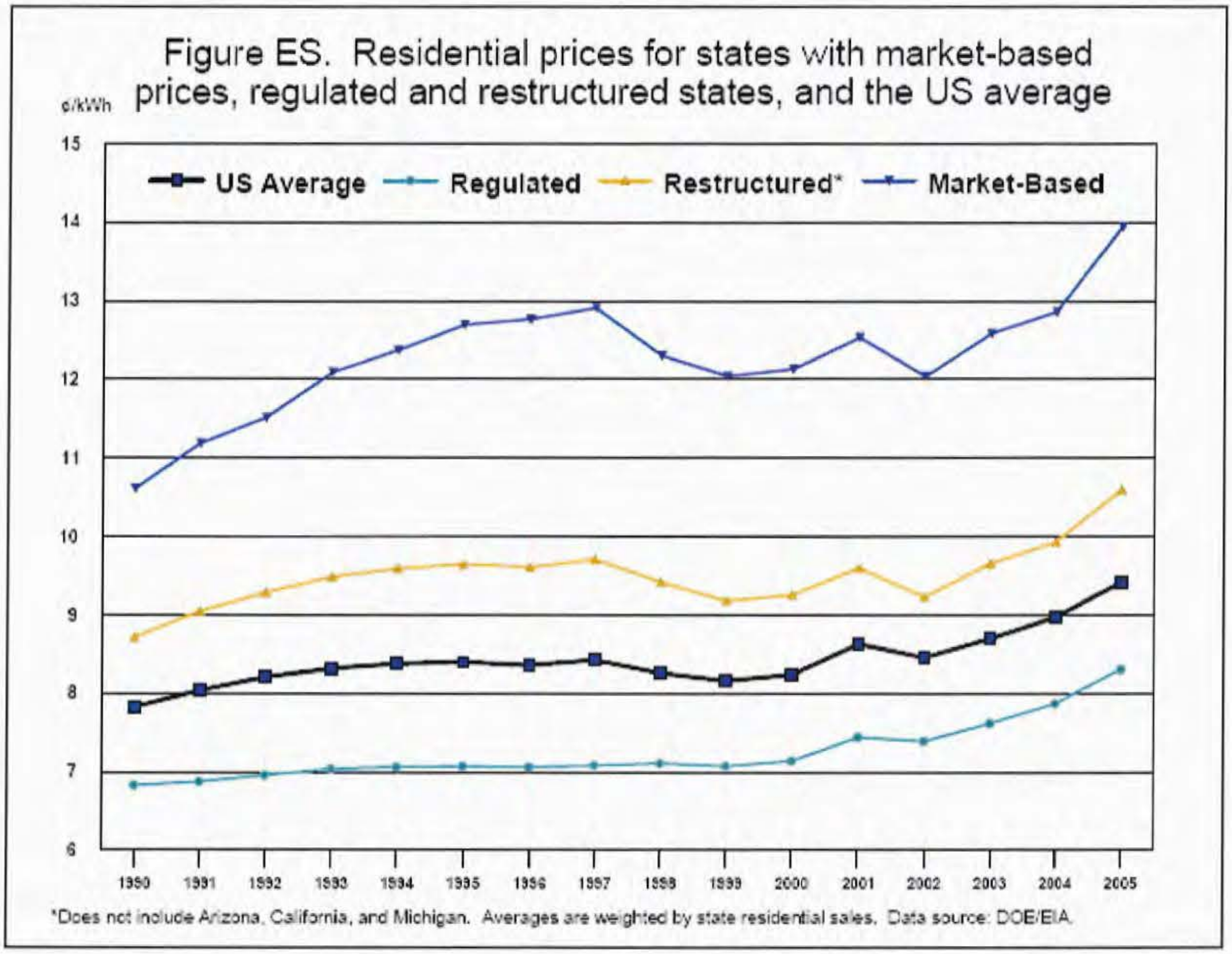
[1]The states included in this group of restructured states are, Connecticut, D.C., Delaware, Illinois, Massachusetts, Maryland, Maine, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Excluded are



All four trend lines show increasing prices in the last few years. The regulated states' prices are moving at about the same rate as the U.S. average between 2002 and 2005. The national average price increased by 11.3 percent and the weighted-average

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California, which suspended its retail access, and Arizona and Michigan, which continue to control utility generation cost.

[2] These states are, Alabama, Arkansas, Colorado, Florida, Georgia, Iowa, Idaho, Indiana, Kansas, Kentucky, Louisiana, Minnesota, Missouri, Mississippi, North Carolina, North Dakota, Nebraska, New Mexico, Nevada (for residential), Oklahoma, Oregon (for residential), South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, Wisconsin, West Virginia, and Wyoming.

price for regulated states increased by 12.3 percent and the slope of the linear regression line for that period is nearly identical, at 0.31 for the national average and 0.30 for the regulated state average. For the individual restructured states that comprise the market-based states, all, except Maine, increased at a faster rate from 2002 to 2005 than the national average. New Jersey, New York and D.C. were only slightly higher than the national average at 13 percent, 16 percent, and 13 percent respectively. Massachusetts increased by 23 percent during that period.

The prices for the weighted-average restructured states and the weighted-average of the states where the residential customers are now paying market-determined prices increased more (at 14.9 percent and 15.8 percent, respectively) than the U.S. average and the weighted-average of the regulated states, again for the 2002 to 2005 timeframe. The slope of the linear regression line for that period is steeper at 0.44 for all restructured states and 0.60 for the states where the price caps expired. Since many of the states in the restructured group still have some form of price controls, the states where the price controls ended is a better indicator of residential customer pricing under the current restructuring arrangement in those states.

It should be noted that this analysis does not include the impact of the substantial price increases that occurred in 2006, including Delaware and Maryland that ended the transition period this year for most residential customers.

In states where the transition period has ended and the generation portion of the customers' bills have been determined by the market, prices have increased faster than the national average and in states that did not restructure. Non-restructured states and some restructured states still in a transition period generally have increased about the same as the national average. It should be noted too that most non-restructured states remain at prices below the national average.

The evidence suggests that, at least so far, no discernable benefit can be seen for customers in restructured states once the rate caps have expired. Increasingly the evidence is beginning to now suggest that prices for customers in restructured states may actually be increasing faster than for customers in states that did not restructure.

Wholesale Markets

The impact of hot summer weather and the major hurricanes that hit the Gulf States in 2005 (and the subsequent impact on natural gas prices) resulted in the power price spikes that occurred nearly nationwide. The higher natural gas prices of December were also apparent in the country as a whole. During 2004 and early 2005, wholesale power prices above $100/MWh were a rare occurrence. However, in the second half of 2005, wholesale electricity prices over $100/MWh were much more common. For example, at the Mass Hub, 28 percent of the hours from April 2005 through March 2006 saw wholesale prices greater than $100/MWh. This compares to less than two percent at those levels for the twelve months prior to April 2005. Regions such as the Midwest (MISO), and Southeast (Florida, Southern Co.) were seeing wholesale prices over $100/MWh for the first time in several years.

A factor that is often mentioned as having a strong influence on electricity prices is the price for natural gas. However, the hourly power prices and the price for natural gas are not always perfectly correlated. Volatility in PJM electricity prices began *before* the big jump in natural gas prices, which started in September and continued through the year. However, the monthly weighted average PJM price actually began to *fall* through November. This suggests that hot weather was more of a factor than natural gas prices during the summer (when load increases) and fall (when load decreases). Natural gas prices impact electricity prices, but other factors are involved as well.

Clearly, one of those other factors is the frequency that the market price is being determined on the vertical portion of the supply curve. When the wholesale market price is set in this area, during peak hours, the price can climb quickly and to hundreds of dollars per MWh. During peak hours, the demand for electricity increases to a point where the highest priced generation units may be needed to operate to meet the demand. For those hours, the price for all power is set by the highest priced marginal generation units, often units that use natural gas. The PJM Market Monitoring Unit's 2005 State of the Market Report, states that combustion turbine (CT) generation was the marginal unit 23 percent of the time during 2005. This figure does not include gas-fired combined-cycle generation, which would include most new units added to PJM in recent years and other marginal steam generation units. Therefore, for over 2,000 hours of the year CT units are determining the price. This has an impact on the overall wholesale price and eventually, on retail customers.

Since generation units that use natural gas are often on the margin, the bid price (not cost) for these units set the market price for that location. However, while natural gas units were 27.5 percent of PJM's installed capacity at the end of 2005, natural gas generated only 5.9 percent of the total generation in 2005 in PJM. *Over 90 percent of the generation during 2005 was from coal and nuclear units.* This underscores the impact of the marginal-bid price determining the market price and its impact on price that retail customers eventually pay.

Electric market characteristics suggest that the market structure is not a robustly competitive one, as was hoped when restructuring began. Because of high supplier market concentration, the difficulty of entry from other firms to build new generation, limited entry from outside the area due to transmission access constraints, and existing market rules, the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace.[3] There is also an inelastic demand for electricity, particularly in the short-run, since customers have few practical substitutes. All these factors suggest the possibility that market conditions permit suppliers to exercise significant market power.

Coordinated interaction and tacit collusion among suppliers also could have particular relevance for electricity markets. The nearly continuous interaction that suppliers have in Regional Transmission Organization (RTO) markets can allow firms to excise market power and utilize anti-competitive bidding strategies. While transparency is important for markets to perform well, it can have the unintended result of creating

[3] Market structure issues were discussed in more detail in the 2005 Market Performance Review.

markets that facilitate collusive supplier behavior. A lack of publicly available information impairs the ability to more fully assess market behavior. However, studies have shown that anti-competitive bidding strategies are possible and the 2000-2001 western power crisis demonstrated that it can and does happen. Given the fact that such strategies have been shown to be possible and successful, it is likely that suppliers are currently using strategic bidding techniques and withholding strategies to raise the price, strategies that would be less effective in a more competitive market. These strategies are particularly effective during periods of relatively high demand. RTO market monitors and the Federal Energy Regulatory Commission do not examine markets for possible coordinated interaction and tacit collusion or the impact on market prices.

These are the result of structural characteristics and are an intrinsic part of the electric supply industry. Barring a significant technological breakthrough, appropriate public policy has to be shaped to fit these structural characteristics, and not be based on what works in other industries or on notions of what should work in theory.

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Part A

Results and Update of Electric Power Industry Restructuring Activities

Introduction

This is the sixth year that a section of the SCC's report to the Virginia General Assembly and the Governor has been done on the development and performance of U.S. wholesale and retail electric power markets, as required under the Virginia Electric Utility Restructuring Act. Past reports have provided detailed descriptions of the development of the regional wholesale markets and state retail markets. This has included the formation and growth of the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), descriptions of the markets they operate, and analysis of the performance of these regional wholesale markets. Also included in past reports was the development of state retail markets, such as shopping status, offers to residential customers, and details on state legislation and regulatory commission implementation. Last year's report also offered a perspective on the lessons learned to date from the market results.

This year's report again provides an overview and update of the wholesale and retail markets. The emphasis this year is on prices. Wholesale prices were clearly significantly impacted by the major weather events of 2005, including warm summer weather in the mid-Atlantic area and Hurricanes Katrina and Rita and the subsequent run-up of natural gas prices. These events had an impact on retail prices as well. This year's report is again divided into two parts. Part A provides an overview of state restructuring activity, retail prices by state, and regional wholesale prices. Part B provides an analysis of restructured state prices compared with prices in states that did not restructure and a perspective on the results of industry restructuring so far and how it relates to the legislative and regulatory goal of fostering the development of competitive wholesale and retail markets.

Retail Markets

National Overview of State Restructuring Activity

The overall status of state retail access has remained relatively unchanged for several years. At this time, as shown in Figure 1, sixteen states and the District of Columbia have fully implemented their legislation and commission orders and currently allow full retail access for all customer groups. Two states allow retail access for larger customers only; Nevada, which modified its original law to limit access to just larger customers, and Oregon, whose original law limited retail access to larger customers. Six states that passed restructuring legislation later delayed, repealed, or indefinitely postponed implementation. Oklahoma and West Virginia passed restructuring legislation but stopped short of implementation; Arkansas and New Mexico repealed their laws; in September 2001 California suspended the retail access program it already had implemented, more than one year after the beginning of the California and western power crisis. Montana also has been dealing with the severe aftermath of the western power crisis and extended the transition period to retail access for smaller customers to 2027.

Figure 1. Status of State Retail Access

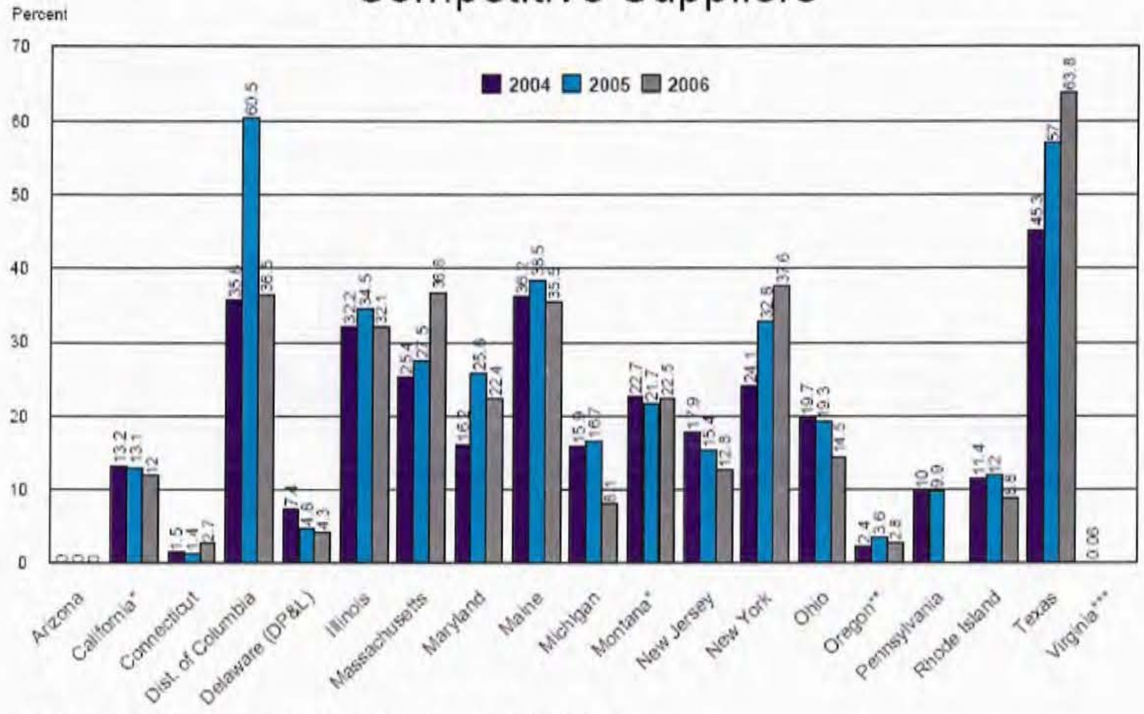
Since the power crisis in California and the West began in mid-2000, no additional states have chosen to adopt retail access. Twenty-six states are not considering retail access or restructuring at this time, and none of these states appear to be working in any meaningful way toward passage. No state has passed restructuring legislation since June of 2000, when the California and western power crisis was just beginning to take shape. Many states that did not pass legislation were considering it, however, they either gradually lessened their efforts to allow time to consider what was occurring in the West, or they abruptly stopped any activity that was ongoing at the time. A total of 34 states have repealed, delayed, suspended, or limited retail access to just large customers, or are now no longer considering retail access.

In addition to the western power crisis, the electric supply industry was beset by a series of other widely reported problems, including the Enron disclosures and collapse in late 2001, revelations of market price manipulation strategies, disclosures of accounting improprieties and data misreporting, and the August 2003 blackout, the most extensive blackout in North American history. This year's significant price increases in several restructured states will likely further discourage any action by states that have not restructured.

Retail Market Activity

Figure 2 shows the percent of the total state electric load that is served by competitive suppliers, for 2004, 2005, and 2006. Five states saw an increase in the percent of total state load served by competitive suppliers in 2006 when compared to 2005, Connecticut, Massachusetts, Montana, New York, and Texas. Three of these states had percentages above 30 percent – Massachusetts, New York, and Texas. Texas had the highest percentage at almost 64 percent of the state's total load and the only state above 40 percent. Eleven states had lower percentages for 2006 than 2005. DC had a considerable decrease from over 60 percent to 36 percent of total load.

Figure 2. Percent of Total State Load Served by Competitive Suppliers

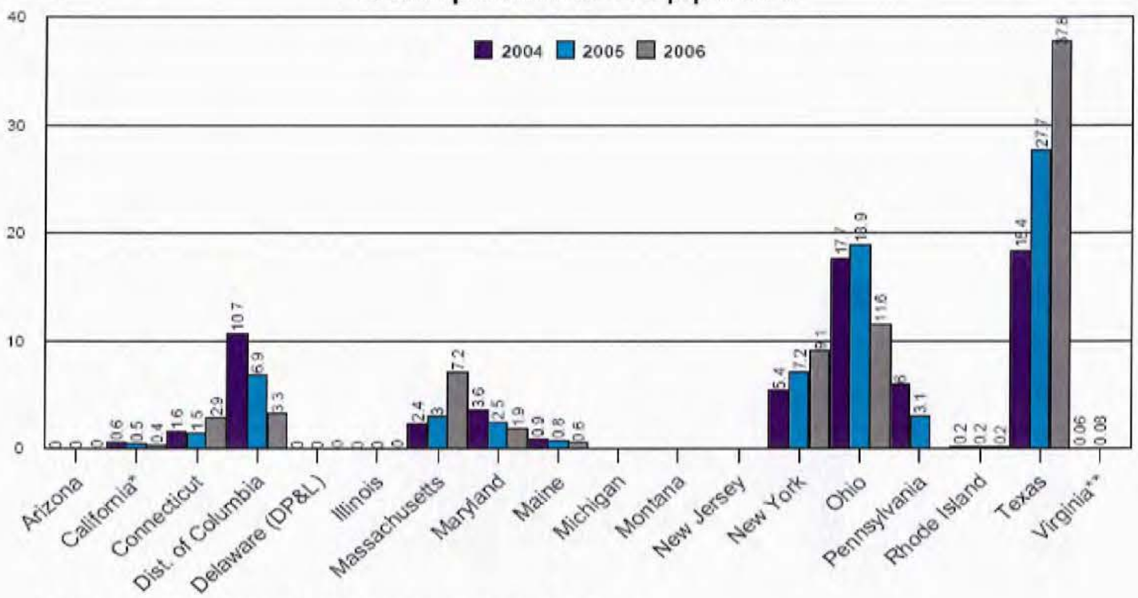


*California retail access was suspended, Montana delayed residential retail access.
**Oregon has retail access for large customers only.
***Virginia percentages are percent of customers, all others are percent of load.
Data Sources: KEMA, Inc., "Retail Energy Foresight," June/July 2004, May/June 2005, March/April 2006 and the Virginia State Corporation Commission.

Figure 3 shows the percent of residential load served by competitive suppliers. Only four states had percentages of the residential load above five percent in 2006, Massachusetts, New York, Ohio, and Texas. Texas was the highest state residential percentage at almost 38 percent of the residential load being served by competitive suppliers. DC and Ohio had significant decreases and many states remain at or very close to zero percent of the residential load being served by competitive suppliers.

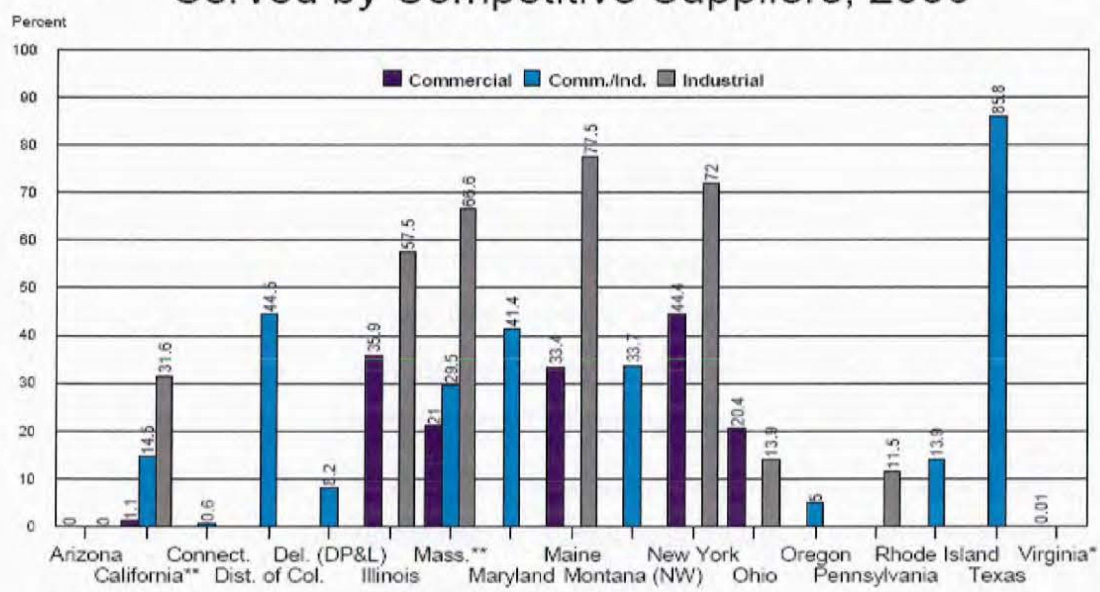
As Figure 4 shows, the overall picture for larger customers is considerably different. Nine states have at least one large customer category above 30 percent of the customer load served by competitive suppliers and five states had a large customer category above 50 percent. Texas had the highest percentage for the large customer categories, at nearly 86 percent of commercial and industrial customers being served by competitive suppliers. Five state percentages were below ten percent.

Figure 3. Percent of Residential Load Served by Competitive Suppliers



*California retail access was suspended, Montana delayed residential retail access.
**Virginia percentages are percent of customers, all others are percent of load.
Data Sources: KEMA, Inc., "Retail Energy Foresight," June/July 2004, May/June 2005, March/April 2006 and the Virginia State Corporation Commission.

Figure 4. Percent of Commercial and Industrial Load Served by Competitive Suppliers, 2006



*Virginia percentages are percent of customers, all others are percent of load.
**For California and Massachusetts, the category shown as "Comm./Industrial" is large commercial.
Data Sources: KEMA, Inc., "Retail Energy Foresight," March/April 2006 and the Virginia State Corporation Commission, 2006.

Retail Prices

This section examines state retail prices by region. To examine retail price trends, data from the U.S. Department or Energy, Energy Information Administration (DOE/EIA)[4] and individual state sources are used and plotted. The DOE/EIA price graphs are in nominal dollars, unless otherwise noted, and are total bundled retail prices reported for the state.

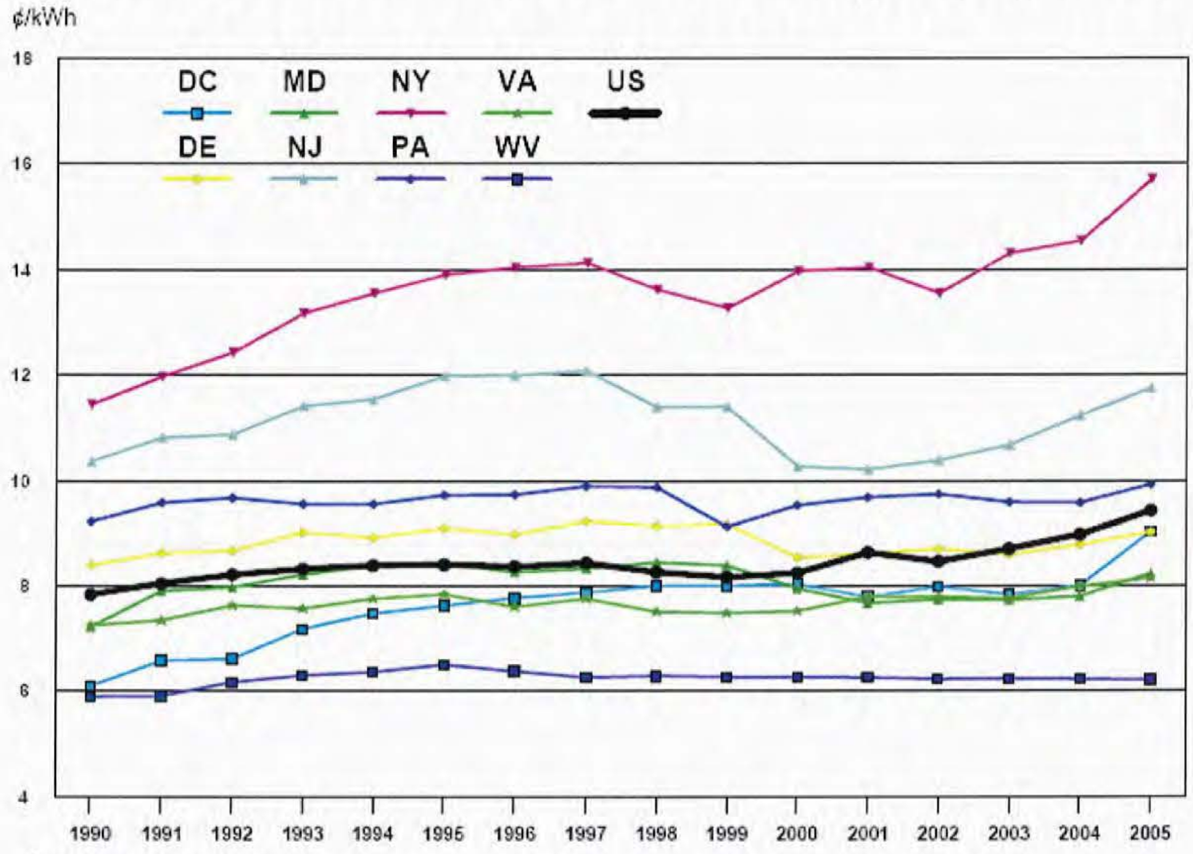
Mid-Atlantic

The U.S. average residential price for electricity has increased over the four years from 2002 to 2005 by 11.3 percent. For states in the mid-Atlantic area, shown in Figure 5, for the same time period (2002 to 2005), four states had increases less than the national average and one fell slightly (West Virginia, by less than one-half of one percent). For these four states, Delaware, Maryland, Pennsylvania, and Virginia, most of the residential customer prices in the state were still controlled during a transition period. West Virginia, the only state in the region to see a decrease for the period, did not restructure its electric industry. Two other states, New Jersey and New York, and the District of Columbia had increases that were greater than the national average. For New Jersey and New York, the increases were 13 and 16 percent respectively. Both of these states have the generation portion of the customers' bills (for most residential customers) determined in the market.[5] DC increased 13.1 percent during this period, 12.8 percent between 2004 and 2005 alone, when the transition period ended in early 2005. (Further details are provided on New Jersey, Delaware, and Maryland below, including 2006 price increases.)

[4] U.S. Department or Energy, Energy Information Administration, Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions Report."

[5] The transition period ended August 2003 for New Jersey residential customers. In New York, the transition period ending varied by company.

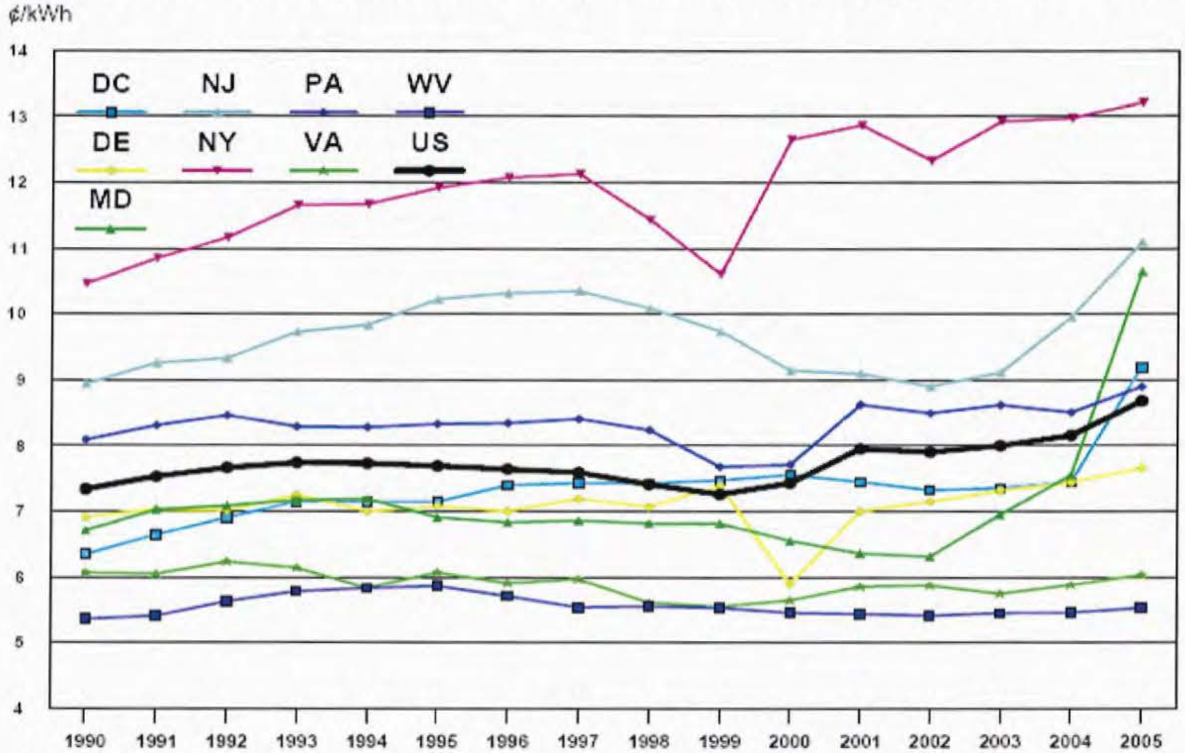
Figure 5. Mid-Atlantic Residential Average Retail Price



Data Source: DOE/EIA

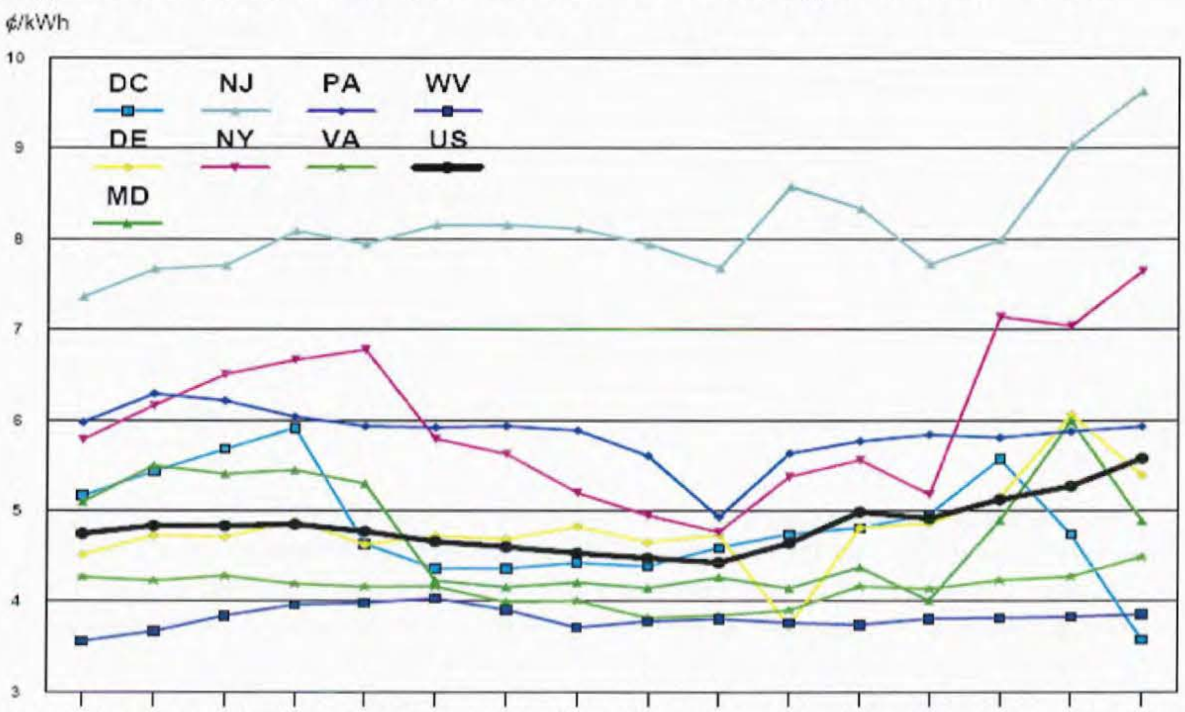
A similar pattern emerges for commercial and industrial customer retail prices in the mid-Atlantic region. Figure 6 shows that commercial customer average prices for the region have also increased significantly, particularly for New Jersey and Maryland customers. For industrial customers in the region, shown in Figure 7, New Jersey and New York have both seen significant increases since 2002 through 2005. The price for DC appears to drop considerably in 2004 and again in 2005. However, this is likely a problem with the DOE/EIA data set's small sample size for industrial customers in a few areas. Examining the data closer reveals that in 1993, EIA reported 156 industrial customers in DC. For 1994 through 2003, they report just one industrial customer, two in 2004, and one again in 2005 (looking at the monthly data for 2005). In contrast, EIA reports over 200,000 residential customers and over 26,000 commercial customers in DC for 2004. Possible explanations may be that there simply are not that many industrial customers in DC to begin with and industrial customers that are present are

Figure 6. Mid-Atlantic Commercial Average Retail Price



Data Source: DOE/EIA

Figure 7. Mid-Atlantic Industrial Average Retail Price



Data Source: DOE/EIA

being served by competitive suppliers that are not being counted sufficiently in the survey. (Moreover, a price below four cents/kWh – or $40/Mwh – is well below wholesale prices in the area in 2004 and 2005. See PJM prices below in this report.) The customer base is much larger for Delaware and Maryland, which also saw a drop in price in 2005 from 2004. This could be reflecting a lower price (however, still higher prices for this customer group than in 2000) or fewer competitive prices being reported – that is, reflecting the loss of utility customers to competitive suppliers and fewer of the competitive prices being reported.[6]

Several states and distribution companies in the mid-Atlantic region have announced significant price increases for consumers in 2006, including, most notably, Delaware, Pike County Light & Power in Pennsylvania, and Maryland. To examine prices in more detail, residential prices in several states and the auctions used to determine residential prices are discussed.

New Jersey

As was covered in previous Market Performance Reviews, the New Jersey Basic Generation Service (BGS) auction is an Internet-based, simultaneous multi-round descending clock auction.[7] The auction determines the generation price and suppliers for customers that have not selected a supplier themselves. The results of the "fixed-price" BGS auctions (for smaller commercial and residential customers) are shown in Table 1. Comparing the first 12-month fixed-price BGS auction results in 2002 to the third 12-month auction in 2004, prices increased modestly for three of the four New Jersey companies involved, from about seven percent to just over nine percent, and decreased even more modestly, just over four percent, for the fourth company. Comparing the 34 month auction in 2003 with the 36 month auction in 2004, prices

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[6]In Maryland for example, EIA reports a total number of industrial customers in the state at 15,673 in 2004, but 10,573 were utility customers in December of 2004. This suggests about one-third of these customers may be served by competitive suppliers – where the prices may or may not be accurately reflected in the state's aggregate data. A similar pattern is seen for Delaware, having a lower customer base of 561 total industrial customers with 356 being utility customers for December 2004.

[7]A summary of how the auction works and past auction results are in the 2004 Performance Review.

decreased slightly, from less than one percent for three of the companies to almost two percent for the remaining company. However, prices in the 2005 and 2006 auctions increased significantly above the 2004 auction prices. Comparing the 36 month auction in 2004 to the 36 month auction in 2005, prices increased over 18 percent for Public Service Electric & Gas, about 20 percent for Jersey Central Power & Light and Atlantic City Electric, and just over 28 percent for Rockland Electric. The increases from 2005 to 2006 were over 50 percent for all four companies (the percentage increases are shown in the last column of the table). The percent increase from 2004 (36 month term) to the 2006 prices ranged from 83 percent increase for Jersey Central to over a 98 percent increase for Rockland. Nearly all the residential customers in the state receive basic generation service (see Figure 3).

Table 1. Results of the "Fixed Price" New Jersey Auctions (cents/kWh)

	2002 Auction	2003 Auction		2004 Auction		2005 Auction	Percent Increase - 04 to 05	2006 Auction	Percent Increase - 05 to 06
	12 month	10 month	34 month	12 month	36 month	36 month		36 month	
Conectiv/ ACE	5.12	5.260	5.529	5.473	5.513	6.648	20.6%	10.399	56.4%
JCP&L	4.87	5.042	5.587	5.325	5.478	6.570	19.9%	10.044	52.9%
PSE&G	5.11	5.386	5.560	5.479	5.515	6.541	18.6%	10.251	56.7%
Rockland	5.82	5.557	5.601	5.566	5.597	7.179	28.3%	11.114	54.8%

Data Source: New Jersey Board of Public Utilities

The auction price percentage increases do not directly translate to the same percentage changes in retail prices. This is because the auction is for determining only the generation component of the total retail price (which also includes distribution and other customer charges) and because of the mix of different contract lengths that remain in effect. The overall bundled price for residential customers was shown in Figure 5.

Delaware

Delaware passed a restructuring law in 1999 and phased-in customer retail access beginning in October 1999 to April 2001, when all customers became eligible to choose a supplier. As seen in Figures 2 through 4, customers of all retail classes in the state (residential, commercial, and industrial), except for a small percentage of the state's commercial customer load, continue to have their electricity provided by one of the state's utilities that served them before restructuring began. The state's restructuring law also mandated a rate cut of 7.5 percent for Delmarva Power & Light Co. (Conectiv) customers and a rate freeze for Delaware Electric Cooperative (DEC) customers. The cap on rates ended on March 31, 2005, for DEC customers and expired on May 1, 2006, for Delmarva customers. The Delmarva rate freeze was originally set to end in September 2003, but was extended as part of a merger agreement involving Potomac Electric Power (PEPCO) and Conectiv.

Another important feature of restructuring in Delaware, and also in common with many other restructured states, was the transfer of utility generation assets from the state-regulated utility to an entity or entities that are not regulated by the state. In 2002, Delmarva sold or transferred all of its generation assets. Since these assets are now owned by wholesale providers, they are subject to Federal Energy Regulatory Commission (FERC) jurisdiction. The Delaware Public Service Commission continues to regulate the distribution companies and generation that is still owned by state-regulated companies.

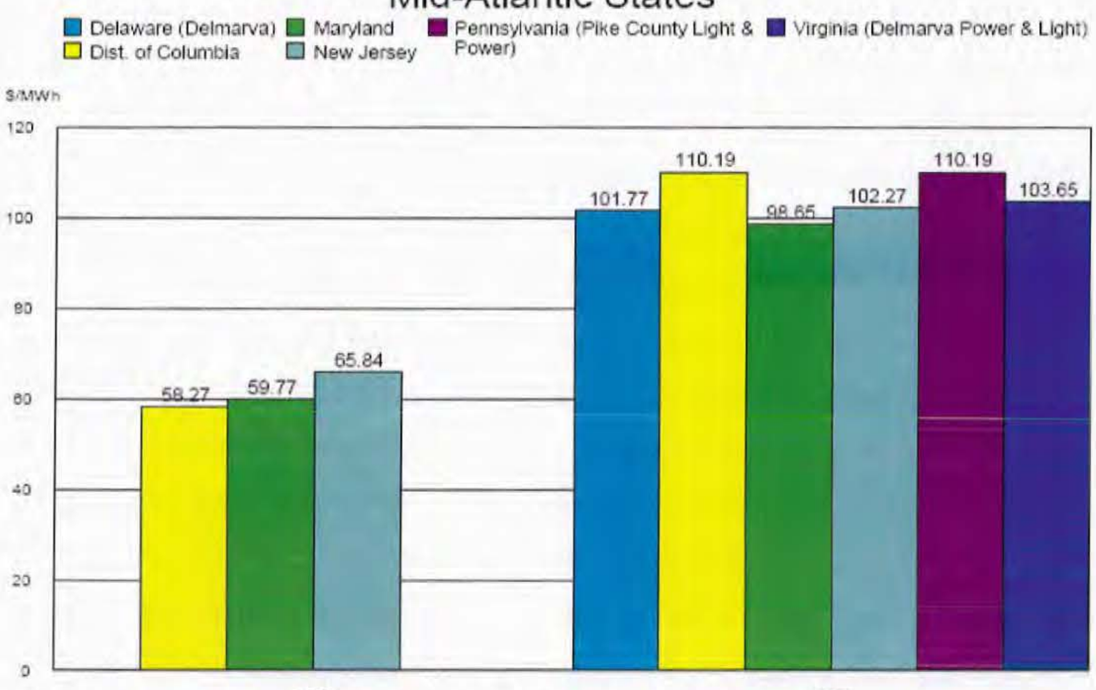
The Delaware Public Service Commission in 2005 determined that power for "Standard Offer Service" will be procured through a competitive bidding process for Delmarva customers. The first bid was conducted in December 2005 ("Tranche 1") and a second and third were held in January 2006 ("Tranche 2 and 3"). The bids were conducted until the load requirements were met for each service type.[8] For residential and small commercial and industrial customers, three procurement lengths, 13 months, 25 months, and 37 months, were bid on by suppliers. The average annual winning bid

[8]The service types were "Residential and Small Commercial & Industrial," "Medium General Service–Secondary (voltage)," "Large General Service–Secondary (voltage)," and "General Service–Primary (voltage)."

prices were all just above ten cents per kilowatthour (kWh). To put this price result into perspective, ten cents per kWh exceeds by about a penny per kWh the *total* average price that residential customers were paying in the state of Delaware during 2005 (see Figure 5) – that is, the nine cents per kWh for the state average includes generation, distribution, transmission, and other utility charges, whereas the ten cent price that resulted from the bidding process is for generation only. These bidding results translated into projected average increases of 59 percent for residential customers and 47 percent to 118 percent increase for business class customers beginning in May 2006 for Delmarva customers.

The bidding and auction price results for Delaware and other mid-Atlantic states are shown in Figure 8. These are weighted average prices for the state (Maryland and New Jersey) or single utility (in Delaware, DC, Pennsylvania, and Virginia).[9] The results in 2005 and 2006 were similar across states for each year, but with a substantial increase in price from 2005 to 2006.

Figure 8. Auction/Bidding Price Results for Generation in Mid-Atlantic States*



*Weighted-average price for state (Maryland and New Jersey) or for utility.
Data Sources: various state sources.

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[9]Weighted by sales data from DOE/EIA.

Maryland

Maryland's restructuring law was passed in April 1999 and retail access began for all customers in the four investor-owned utilities on July 1, 2000. Through settlements reached with the state's investor-owned utilities, most residential customers had rate decreases below the rates in effect in June 1999 and had fixed Standard Offer Service prices for the generation supply portion of their bills for customers that did not choose an alternative supplier. Specifically, residential discounts were about 7 percent for Allegheny Power (APS), 6.5 percent for Baltimore Gas & Electric (BG&E), 7.5 percent for DPL/Connectiv (DPL), and 3 percent for Potomac Electric Power Company (PEPCO). The fixed Standard Offer Service supplied by the utilities expires at different times by customer classes and utility company. The residential fixed Standard Offer Service period (which includes the price caps) ends July 1, 2008 for APS and July 1, 2006 for BG&E. The transition ended July 1, 2004, for both DPL and for PEPCO. Also by July 1, 2004, all price caps remaining for non-residential customers had expired.

After the fixed price standard offer service expires, default rates for customers who do not choose an alternative supplier and continue to receive generation supply from their local utility, are based on bids received in a competitive bidding process. Residential customers of PEPCO and DPL/Conectiv began to receive bid-based Standard Offer Service beginning July 1, 2004 (when the fixed price period ended) for customers who did not choose a competitive electric supplier. As a result of the bidding process in 2004, PEPCO residential customers had the power supply portion of their bills increased by 26 percent and the average annual bills increased by approximately 16 percent (an increase of $164.28 for the average residential annual bill). Total bills for PEPCO small commercial customer increased by approximately 13 percent; medium-sized commercial customer bills increased between 25 to 30 percent; large-sized commercial customers' bills increased approximately 48 percent to 57 percent. DPL/Conectiv residential customers had the power supply portion of their bills increased by 19 percent and average annual electric bill increase of approximately 12 percent (an increase of $130.80 for the average residential annual bill).

The bidding process in 2005 resulted in PEPCO's residential customers' generation standard offer increased by 6.6 percent and the overall annual bill increased by 4.6 percent. DPL customers had the generation component of their bill increase by 8.7 percent and the total annual bill increased by 5.8 percent.

Generation supply price freeze for residential customers of Baltimore Gas and Electric Company ends July 1, 2006, and the competitive bidding process has determined the generation price for standard offer customers. (As noted, prices for residential customers of Allegheny Power will remain frozen 2008.) What has become well known at this time, the results of the bidding from this year would have translated into rate increases for residential customers of 72 percent for BGE (an increase of 132 percent in the power supply portion of the bill), 39 percent for PEPCO (an increase of 59 percent in the power supply portion of the bill), and 35 percent for DPL customers (an increase of 52 percent in the power supply portion of the bill). However, the BGE residential rate increases will instead be phased-in, by legislative enactment.[10]

Maryland's bidding results were similar to Delaware's in terms of price (see Figure 8). For residential customers the electricity supply costs were $97.57 per MWh for BGE, 98.85 per MWh for DP&L, and 101.10 per MWh for PEPCO. Also similar to Delaware, all three of these *generation only* prices are well above the 2005 state average *bundled* price for residential customers of 8.23 cents per kWh (or $82.3 per MWh, see Figure 5), which includes generation, transmission, distribution, and other customer charges.

This was the first bidding for BGE residential customers, and the contract lengths were divided with about one-half of the contracts 11 months, one-quarter 23 months, and one-quarter 35 months. Since DP&L and PEPCO residential service was bid in two previous bids, about one-quarter of the contracts were bid two years ago as 35 month contracts. For this year, three quarters of the contracts were put out for bid this year as one and two year contracts. Maryland had three bids that took place from December 2005 through February 2006. Constellation Energy Group, parent company of BGE, disclosed that it won 70 percent of the contracts to supply BGE's customer load beginning in July 2006.[11]

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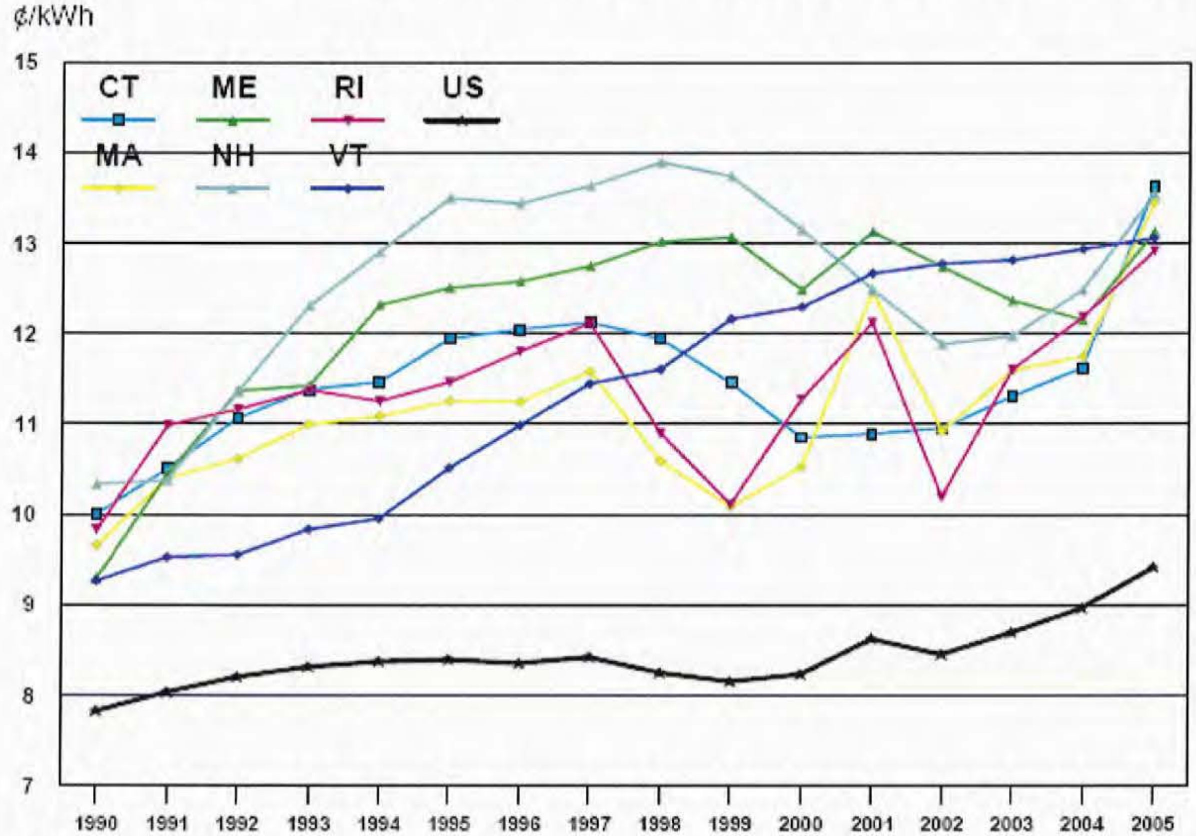
[10]The legislation limited the July 1, 2006 increase to 15 percent for BGE residential customers, allows consumers an option of another deferral beginning June 1, 2007, and adjusts to the full 72 percent increase on January 1, 2008. Customers are required to pay for the deferral with an average monthly charge of $2.19 over 10 years.

[11]*The Baltimore Sun*, "Constellation Defends Profits," June 2, 2006.

New England

All six New England states have had retail electric prices well above the national average for all of the 16 year period shown in Figure 9. Five of the six states have restructured their electric supply industry, Vermont is the only state that has not restructured in New England. In 1990, New England residential prices were 18 percent

Figure 9. New England Residential Average Retail Price

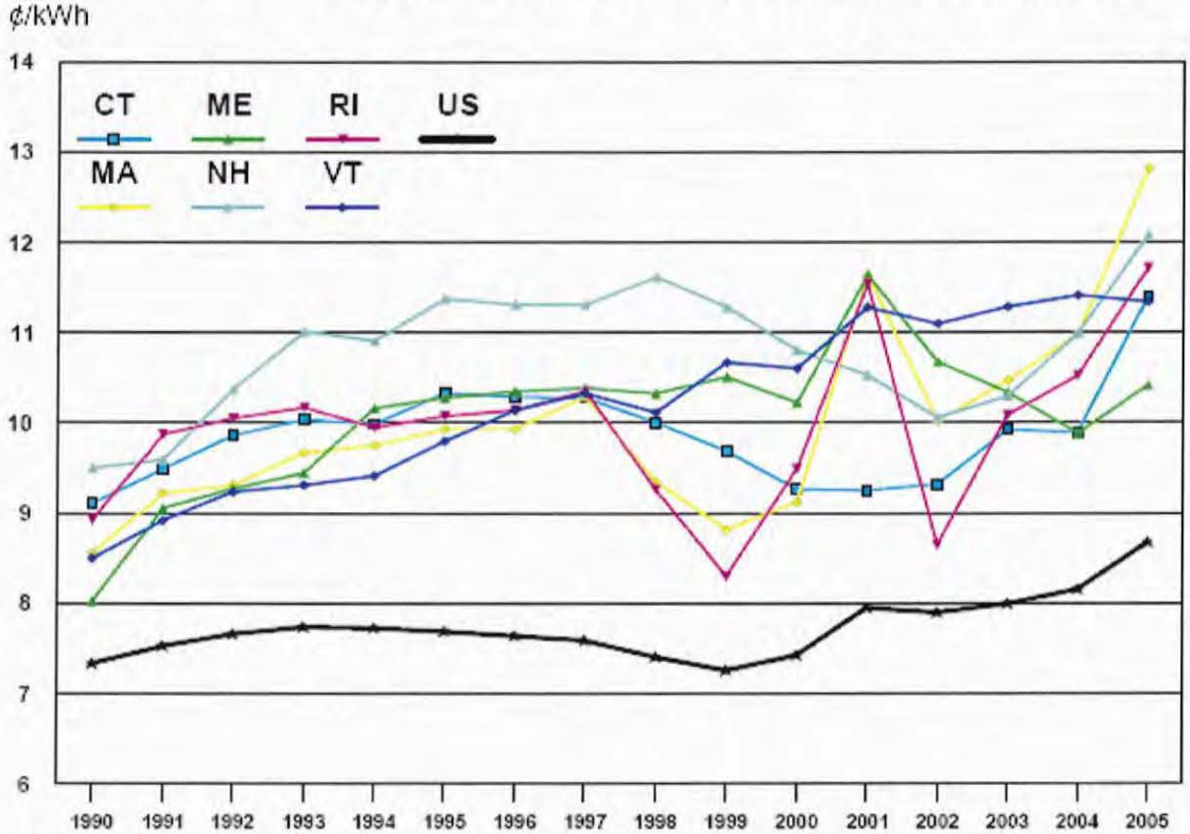


Data Source: DOE/EIA

to 32 percent above the national average. In 2005, that range increased to 37 percent to 45 percent above the national average. All six states had similar prices in 2005, between 12.9 and 13.6 cents/kWh. Except for Maine, which saw a decrease between 2001 and 2004, all other states in the region have seen increasing prices from 2002 through 2005. All six states (including Maine, due to a sharp increase in 2005 above the 2004 price) had higher prices in 2005 than 2002. Four states increased faster that the national average price between 2002 and 2005, Connecticut (24 percent increase), Massachusetts (23 percent), New Hampshire (14 percent), and Rhode Island (27 percent); the national average price increased by 11 percent during that same period.

A similar pattern can be seen for New England commercial customer average prices, shown in Figure 10. Prices have been higher than the national throughout the period shown in the figure. Four states have seen sharply higher prices from 2002 to

Figure 10. New England Commercial Average Retail Price

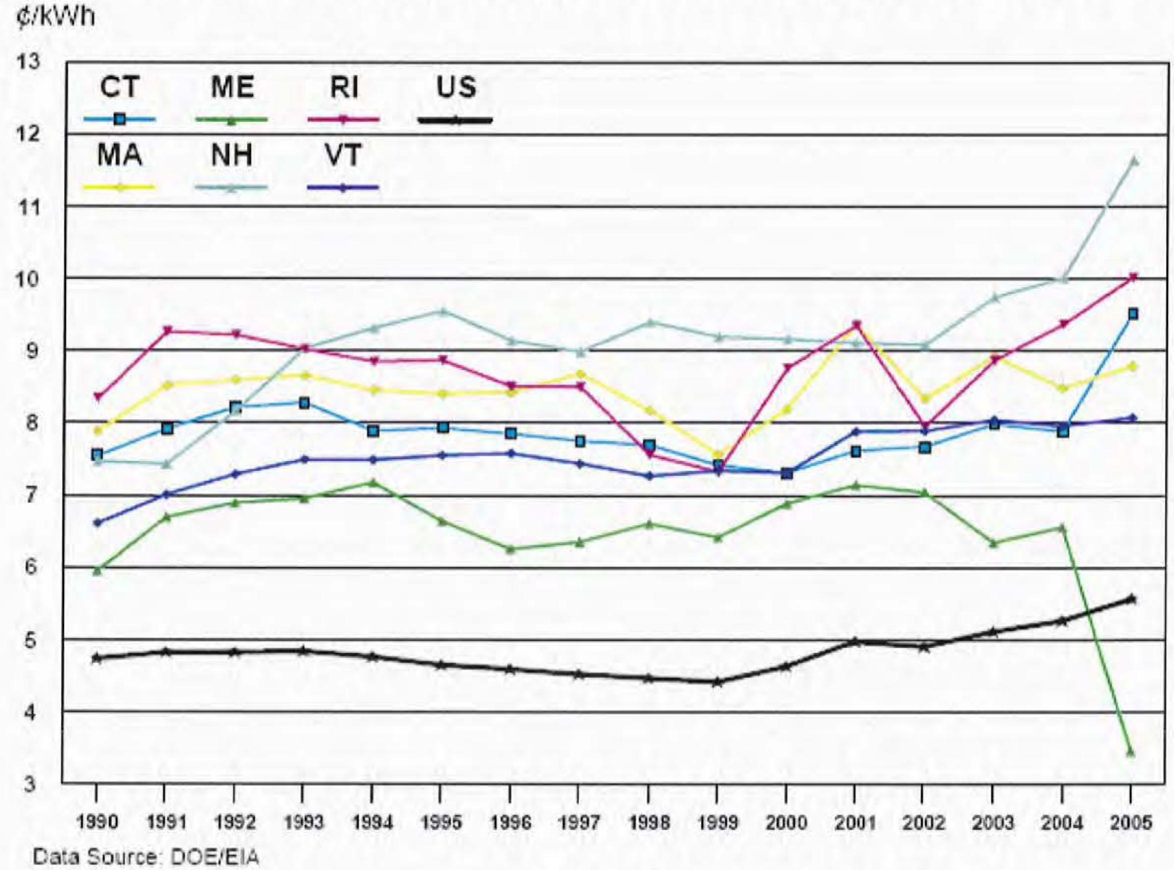


Data Source: DOE/EIA

2005, Connecticut (22 percent increase), Massachusetts (28 percent), New Hampshire (20 percent), and Rhode Island (35 percent). The national average price for commercial customers increased by 10 percent during that same period. Vermont increased by two percent and Maine commercial prices fell by two percent in 2005 from 2002 prices. Similar to residential prices, Maine commercial customer prices fell between 2001 and 2004, then increased in 2005 from the 2004 level. There was a slightly wider range of prices in the region than the residential price, between 10.4 and 12.8 cents/kWh.

Prices for industrial customers in New England have also been consistently above the national average from 1990 through 2005, as shown in Figure 11. The lone exception was the 2005 price for Maine, which had a sharp drop from 2004. However, this is likely due to a small sample size for this customer group in the state or due to a large number of these customers being served by competitive suppliers -- but are not being reported in the data -- or a combination of both factors. Monthly DOE/EIA data shows the number of utility customers in Maine at or about 19 customers for most months in 2004 and 2005. Annual DOE/EIA data report the total number of industrial customers to be 2,832 for 2004. (Also, as with DC discussed above, this reported price is well below wholesale prices in New England – see the New England region in the wholesale section of this report.) This number could be revised in the future, as others have been in the past.

Figure 11. New England Industrial Average Retail Price

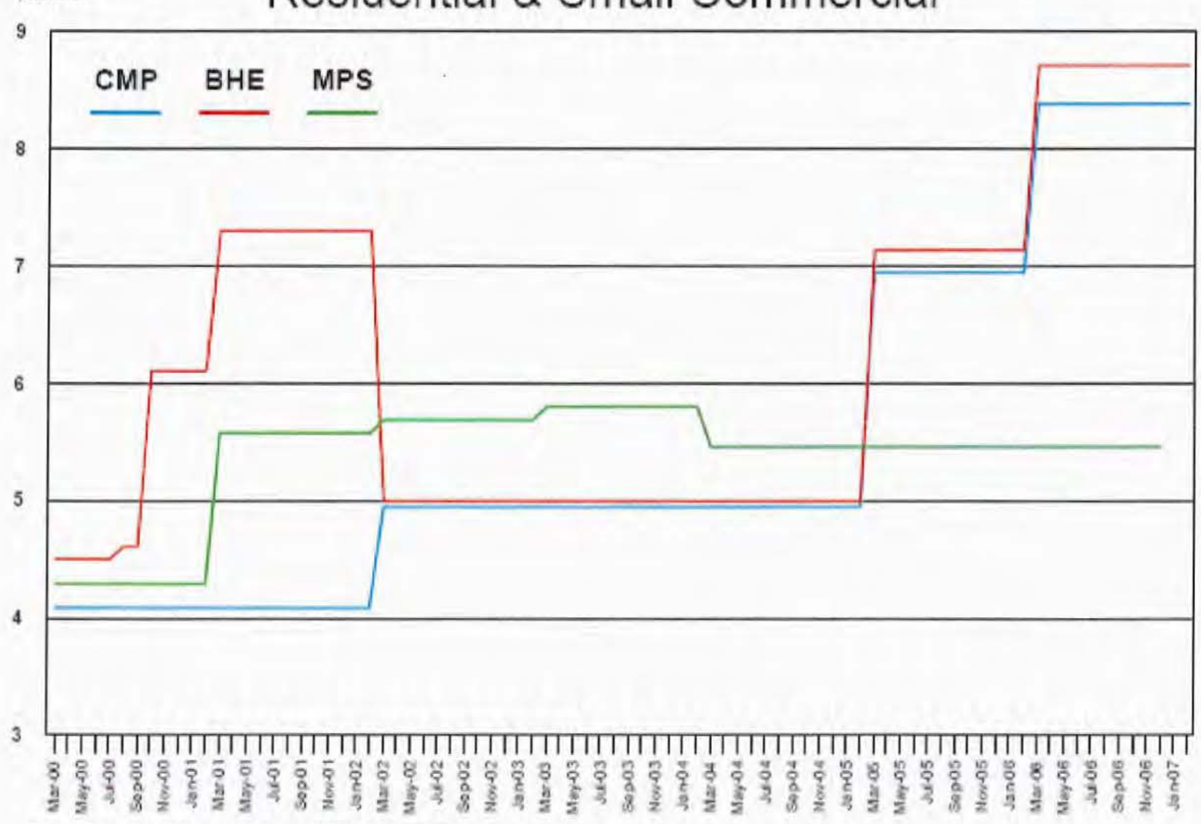


Except in Maine, prices for industrial customers in New England have also increased between 2002 and 2005. The national average industrial price increased by 13 percent from 2002 to 2005. During that same time period, Connecticut increased by 24 percent, New Hampshire increased by 28 percent, and Rhode Island increased by 26 percent. Massachusetts and Vermont increased by 5 percent and 2 percent, respectively, during the 2002 to 2005 period.

Maine

Maine has used a competitive bidding procurement process to determine the standard offer rates since 2000. The bidding process is conducted by the Maine Public Utilities Commission. Maine's restructuring law required complete divestiture of the utilities' generation assets and the distribution companies cannot participate in the bidding (affiliates of the distribution cannot provide more than 20 percent of the standard offer service in the company's service territory). The standard offer prices that resulted from the bidding for residential and small commercial customers for the three distribution companies in Maine are shown in Figure 12. These prices are for generation only. Standard offer prices for all three companies were steady from early 2002 through early

Figure 12. Maine Standard Offer Service Prices
Residential & Small Commercial

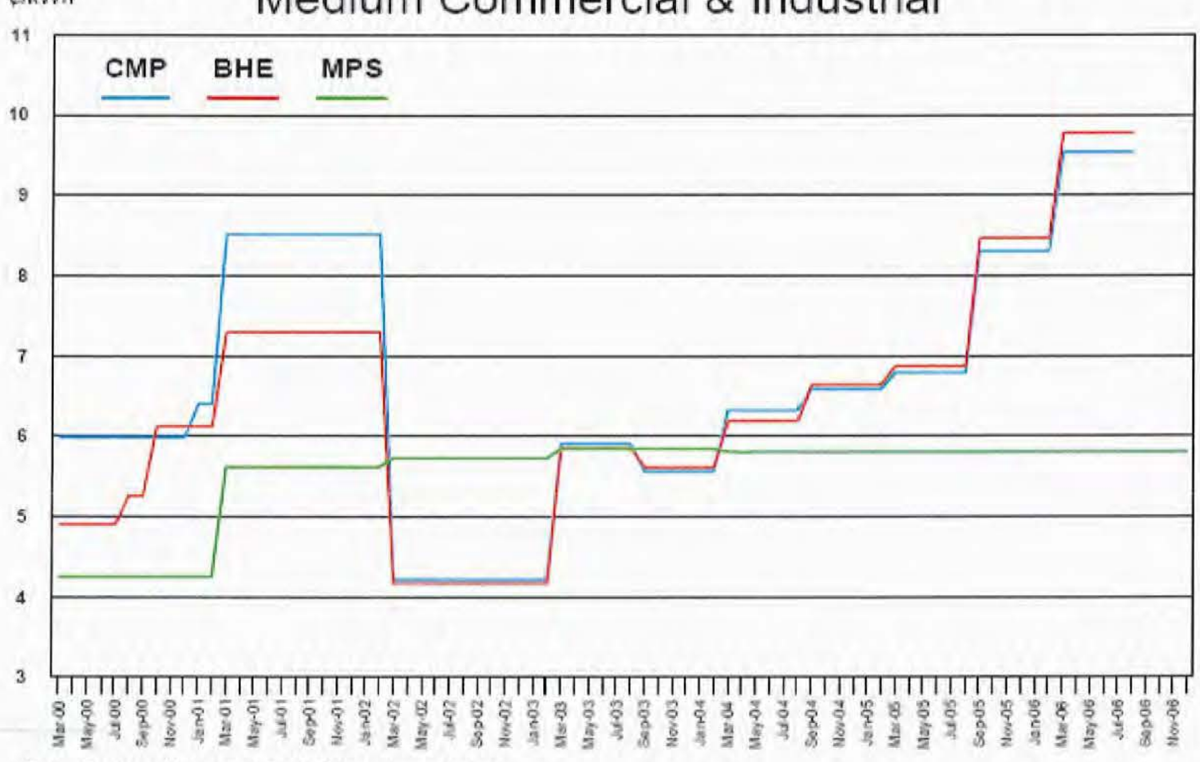


Data Source: Maine Public Utilities Commission.

2005. Prices for Central Maine Power (CMP) and Bangor Hydro-Electric (BHE) increased considerably from about 5 cents/kWh from March 2002 through February 2005, to over 8 cents/kWh beginning in March 2006. This is an increase of 69 percent and 74 percent in the standard offer price for CMP and BHE, respectively. Nearly all the residential customers in CMP and BHE territories are on this standard offer rate for generation service. Maine Public Service (MPS) standard offer service has remained flat, due to long term contract that began in March 2004, and runs through to the end of 2006. As of June 2006, 98 percent of MPS's residential and small commercial customer load was on standard offer service.[12]

Standard offer prices for CMP and BHE medium commercial and industrial customers have also increased steadily since early 2004, as seen in Figure 13. The price has increased by over 70 percent for both CMP and BHE from February 2004 to

Figure 13. Maine Standard Offer Service Prices
Medium Commercial & Industrial



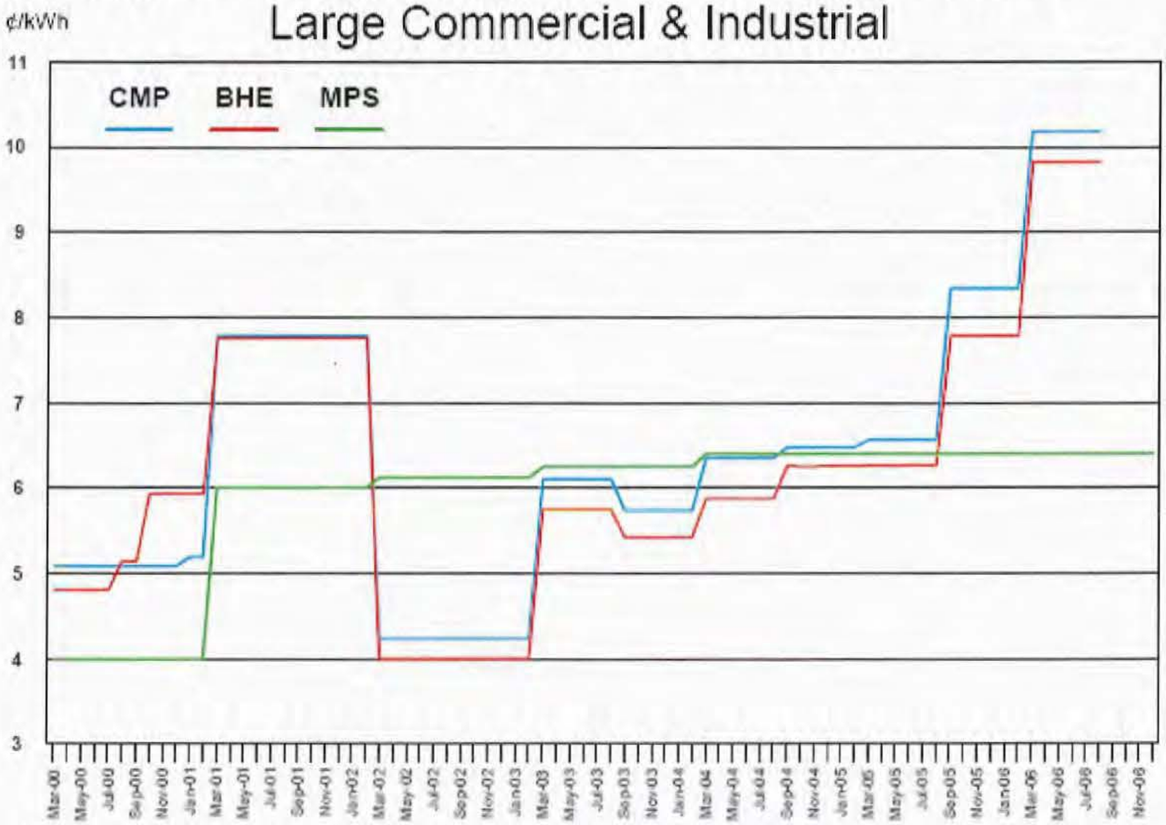
Data Source: Maine Public Utilities Commission.

[12]In July 2003, 36 percent of residential and small commercial load of MPS was served by competitive suppliers, the highest point reached to date for that customer group.

the March 2006 price, which continues through August 2006. For both CMP and BHE, 63 percent of the medium commercial and industrial load were on standard offer service in June 2006. MPS medium commercial and industrial customers are also on a contract that continues through December 2006; 64 percent of these customers' load are on standard offer service as of June 2006.

Standard offer service prices for large commercial and industrial customers reveal a similar pattern, as shown in Figure 14. The standard offer price has increased by over 55 percent for both CMP and BHE from August 2005 to the price that runs through August 2006. MPS standard offer prices are again flat from March 2004 through December 2006. As of June 2006, 13 percent, 43 percent, and 11 percent of the large commercial and industrial customer load for CMP, BHE and MPS, respectively, were on standard offer service.

Figure 14. Maine Standard Offer Service Prices
Large Commercial & Industrial

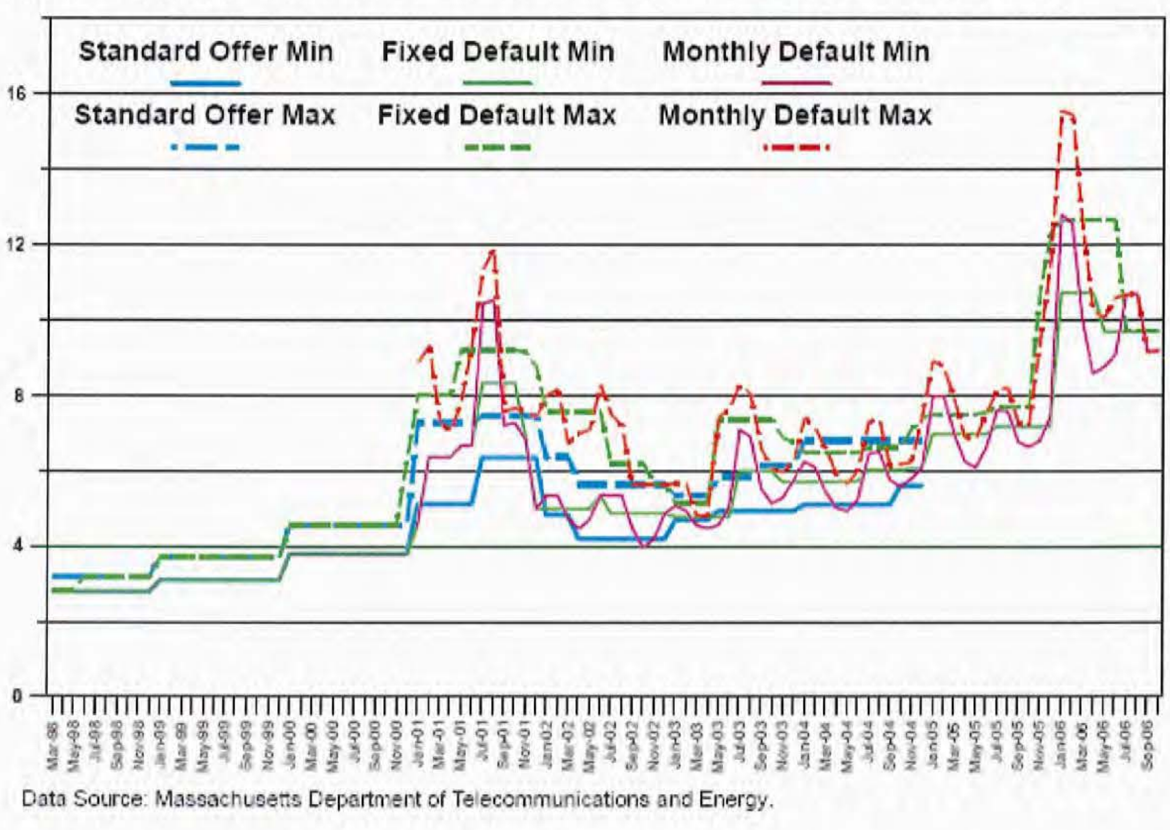


Data Source: Maine Public Utilities Commission.

Massachusetts

Massachusetts ended its "standard offer service" (the state's transitional generation service) and began "basic service" March 1, 2005, for residential customers that have not chosen a competitive supplier (almost 93 percent of the residential customers in the state, see Figure 3). The distribution companies purchase electricity on the market following the procedures of the Massachusetts Department of Telecommunications and Energy. Figure 15 plots the Massachusetts standard offer and default service prices for residential customers back to 1998. These prices are for generation only, not the total bundled prices as shown in the charts of DOE/EIA data, of the maximum and minimum standard offer and default prices for the six distribution companies in Massachusetts. Since the standard offer price ended in early 2005, default prices have increased significantly. The monthly default price spiked to over 15 cents/kWh in January and February of 2006 and remain above 10 cents/kWh through August of 2006. All prices will be above 9 cents through October 2006.

Figure 15. Massachusetts Standard Offer and Default Service Prices for Residential Customers

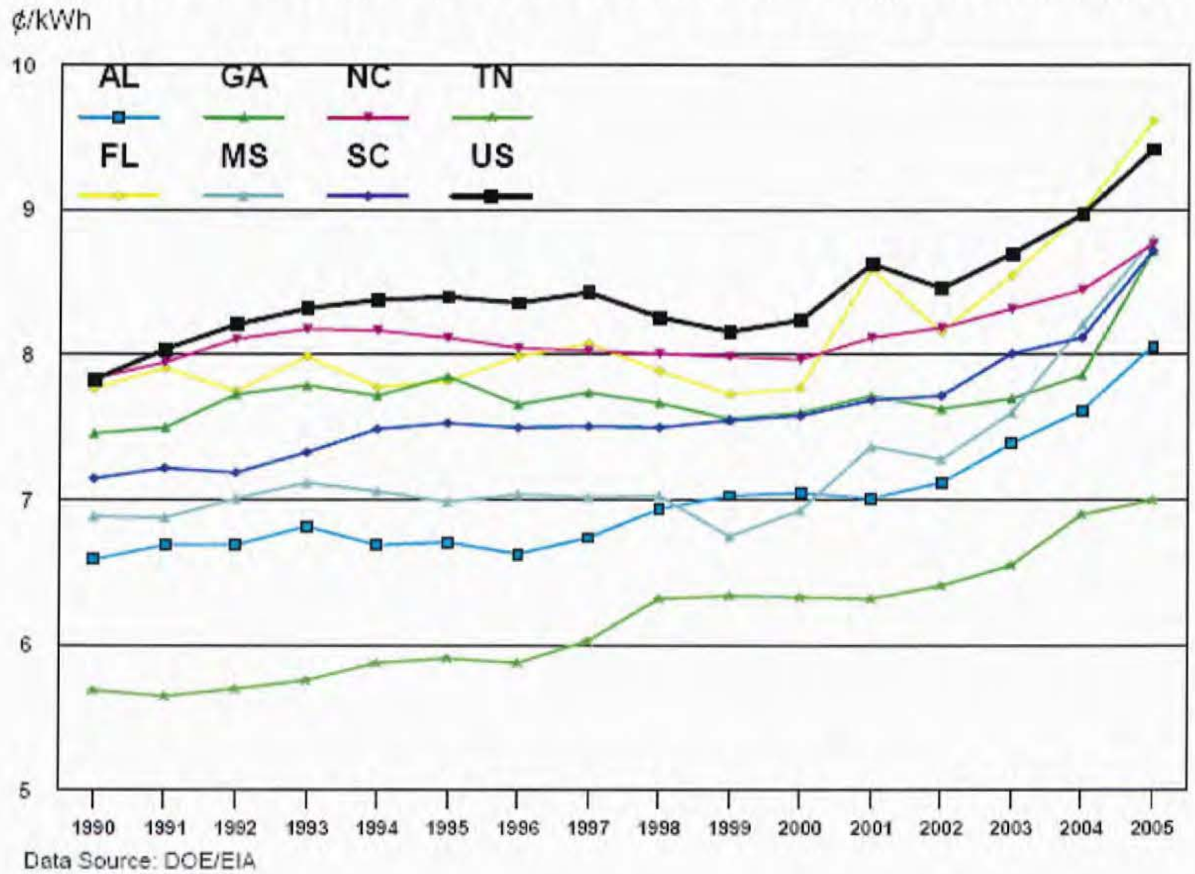


Data Source: Massachusetts Department of Telecommunications and Energy.

Southeast

Southeastern state residential average retail prices are shown in Figure 16. No state in the Southeast region has restructured retail electric supply. Prices in the region were relatively flat for the period beginning in 1990, but have seen significant increases since 2002. Five of the seven states in the region had prices increase faster than the national average of 11 percent between 2002 through 2005. However, every state in the region is below the national average, except Florida, which was only two-tenths on a cent above in 2005 and two-hundredths of a cents above in 2004. Florida has seen an 18 percent increase in residential prices between 2002 and 2005. In several respects, however, Florida is a special case that separates it from most other states in the country. First, similar to other regions of the country, higher natural gas prices and an increasing portion of the generation using natural gas has contributed to price increases. Florida increased from 16 percent of the generation in the state using natural gas in 1994, to 32

Figure 16. Southeast Residential Average Retail Price

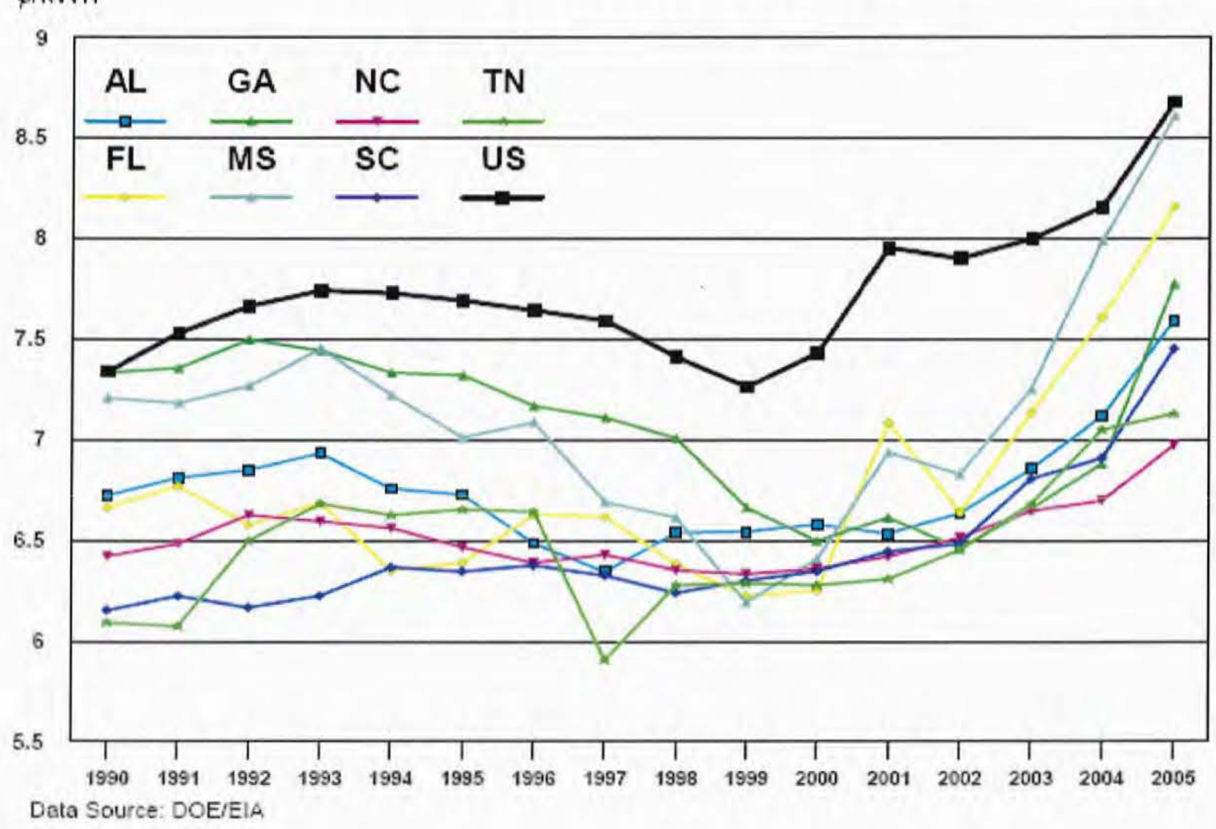


percent in 2003.[13] Second, generation capacity increased by 27 percent between 1994 and 2003 to meet load for a fast growing area of the country. Finally, the state has faced costs related to fixing damage from several recent hurricanes and the "hardening" of their distribution system for future storms.

The fastest price increase in the region was Mississippi, which increased by 21 percent between 2002 and 2005. The state has seen a 131 percent increase in generation capacity between 1994 to 2003 – 94 percent of that increase was natural gas capacity, increasing the percentage share from 9 percent of the state's capacity was natural gas to 57 percent. Most of this new capacity was added by independent power producers.

For commercial customers in the southeast region, shown in Figure 17, prices have generally followed the national trend for commercial customers. Prices fell or were

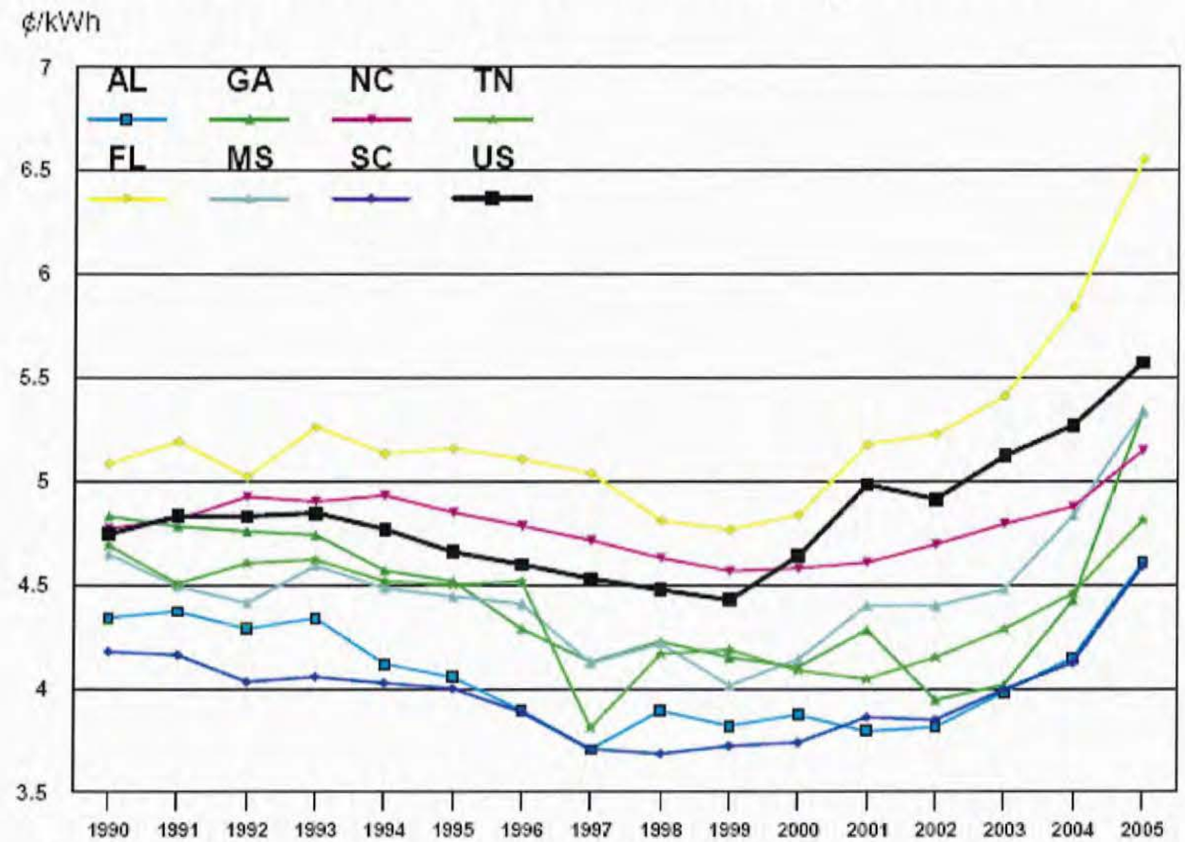
Figure 17. Southeast Commercial Average Retail Price



[13]State capacity and generation figures are based on data in U.S. Department of Energy, Energy Information Administration, "State Electricity Profiles 2003," April 2006.

relatively unchanged through the late 1990s. Then, similar to the pattern seen for residential customers, prices increased considerably since 2002. All the states in the region remained below the national average for this customer category. The price pattern over time is again nearly the same for industrial customers in the southeast region, as can be seen in Figure 18. However, Florida has consistently been above the national average throughout the period shown in the figure, but never by more than one cent/kWh (for 2005, the difference was just under one cent/kWh – before that, the difference was usually one-half of a cent/kWh or less). All other state industrial customer prices were below the national average from 2000 through 2005.

Figure 18. Southeast Industrial Average Retail Price

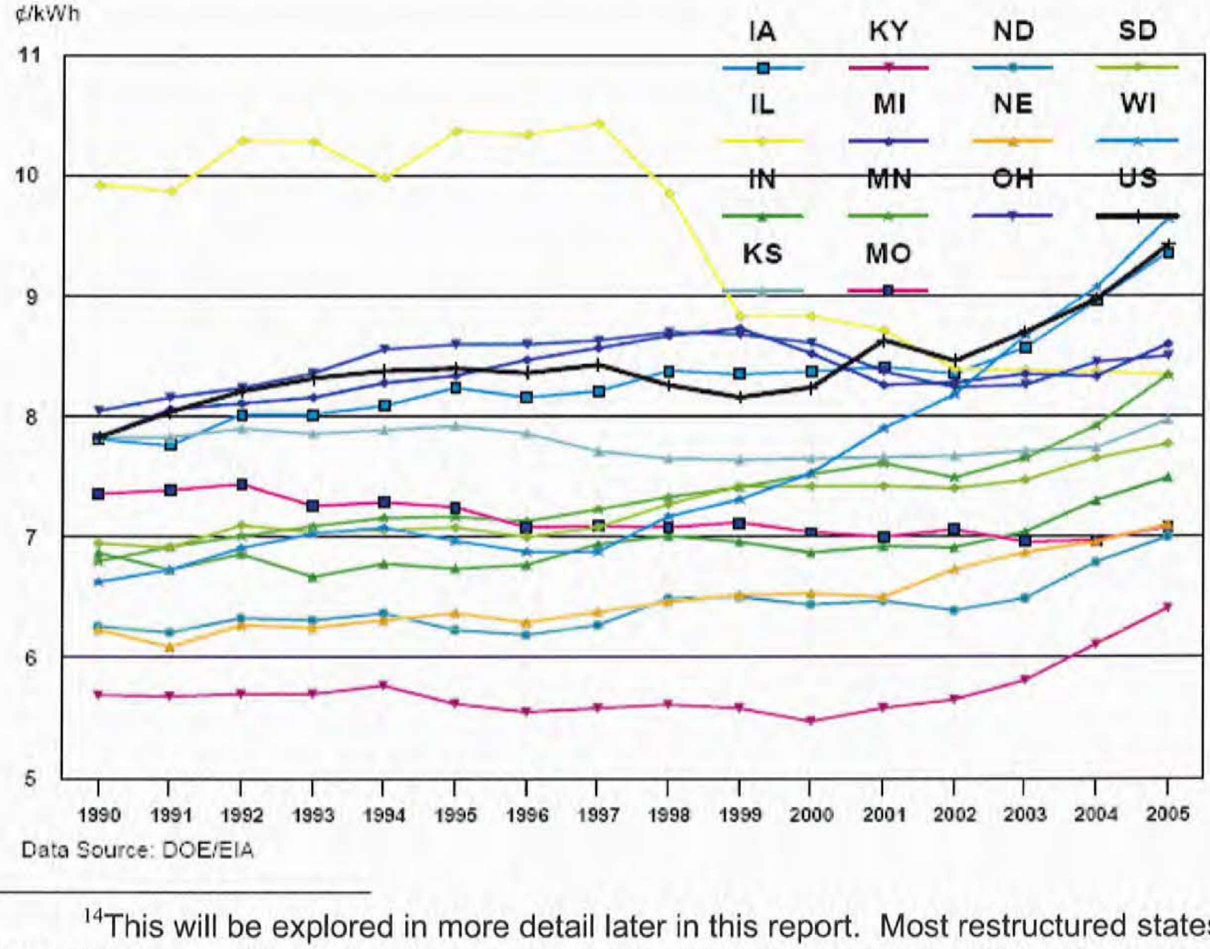


Data Source: DOE/EIA

Midwest

Most states in the Midwest region have not restructured -- the exceptions are Illinois, Michigan, and Ohio. Illinois and Ohio are still in a transition period and customers are not fully seeing market prices at this point. Michigan ended the transition rate caps at the end of 2005, but maintains regulatory control of the generation price with retail access, which is unusual for restructured states (Arizona is perhaps the only other example of this).[14] Midwest regional prices have been the most stable overall of any region in the country. For residential customers in the Midwest region, shown in Figure 19, there are two notable exceptions. Illinois had prices well above other states in the region until, beginning in 1998, a 15 percent and then later an additional 5 percent

Figure 19. Midwest Residential Average Retail Price



Data Source: DOE/EIA

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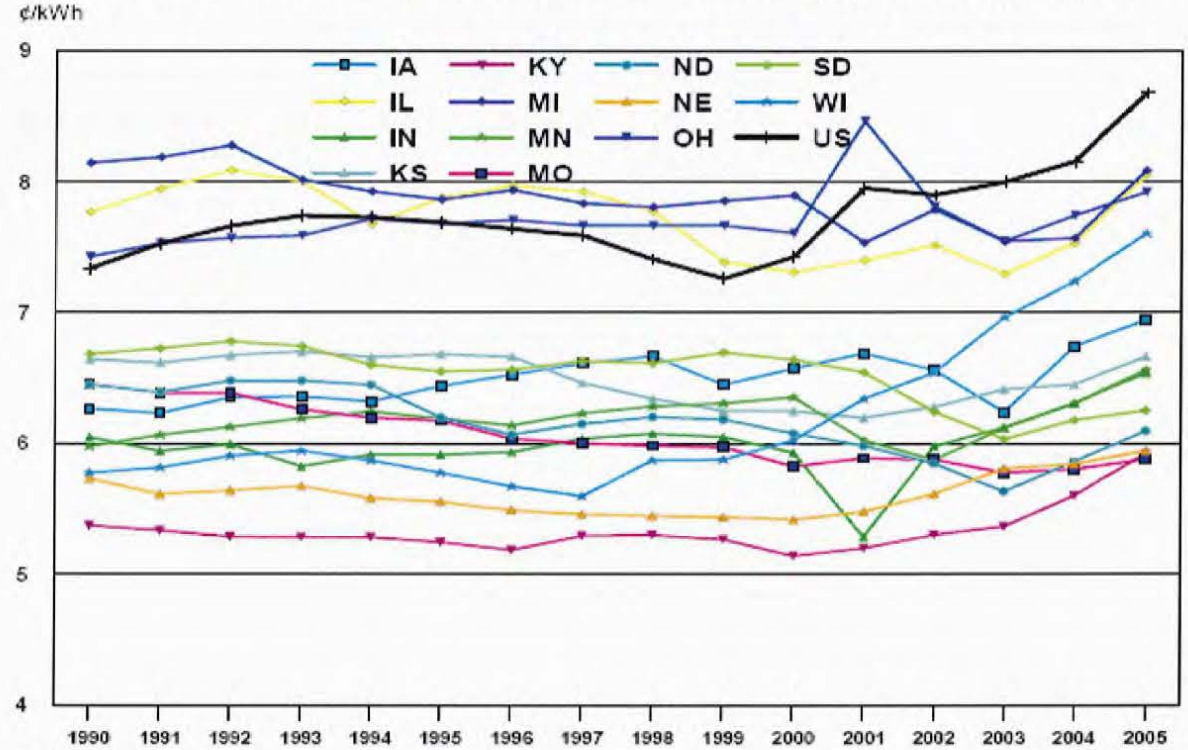
[14]This will be explored in more detail later in this report. Most restructured states have either moved to a market-based means to determine retail price (through a procurement process, wholesale market, or customers purchasing directly from suppliers) or are in a transition period where the price is capped or controlled – but will become market determined after the transition period is over.

discount for Commonwealth Edison and Illinois Power (now AmerenIP) residential customers were applied. As mandated by Illinois' restructuring law, rates will remain frozen until December 31, 2006. Illinois is currently planning to use an auction approach, similar to the New Jersey BGS auction, to procure power supply for customers beginning in 2007.

The other notable exception to the region's relative stability is Wisconsin. The state started well below the national average, but beginning in about 1998, Wisconsin residential customer prices began to rise to slightly above the national average for the last two years in the figure, about 2 tenths of a cents/kWh above in 2005. Wisconsin Electric Power, now We Energies, which serves the Milwaukee area up through eastern Wisconsin into the Upper Peninsula of Michigan, has been adding new generating capacity in its area. They expect to expand total generation from about 6,000 MW currently to approximately 8,300 MW when completed (DOE/EIA data shows the capacity in the state expanded by about 2400 MW between 1994 and 2003, about a 21 percent increase). They are also upgrading existing plants and the distribution system.

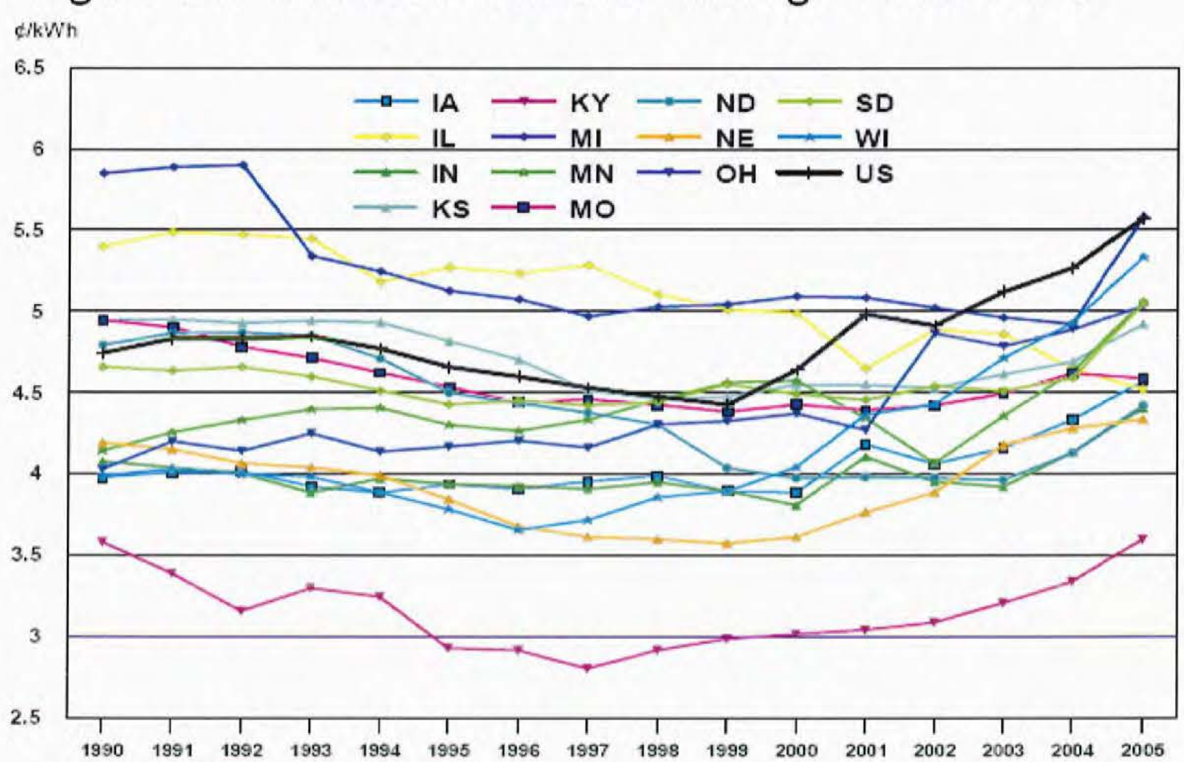
Commercial customer prices in the Midwest, Figure 20, are also relatively stable throughout the period shown in the figure, again, with the notable exception of Wisconsin. All states in the region, including Wisconsin, have been below the national average since 2002. Industrial customer average prices in the region, shown in Figure 21, are again showing a similar pattern, where all states are below the national average (the Michigan average industrial price was nearly identical to the national average in 2005).

Figure 20. Midwest Commercial Average Retail Price



Data Source: DOE/EIA

Figure 21. Midwest Industrial Average Retail Price

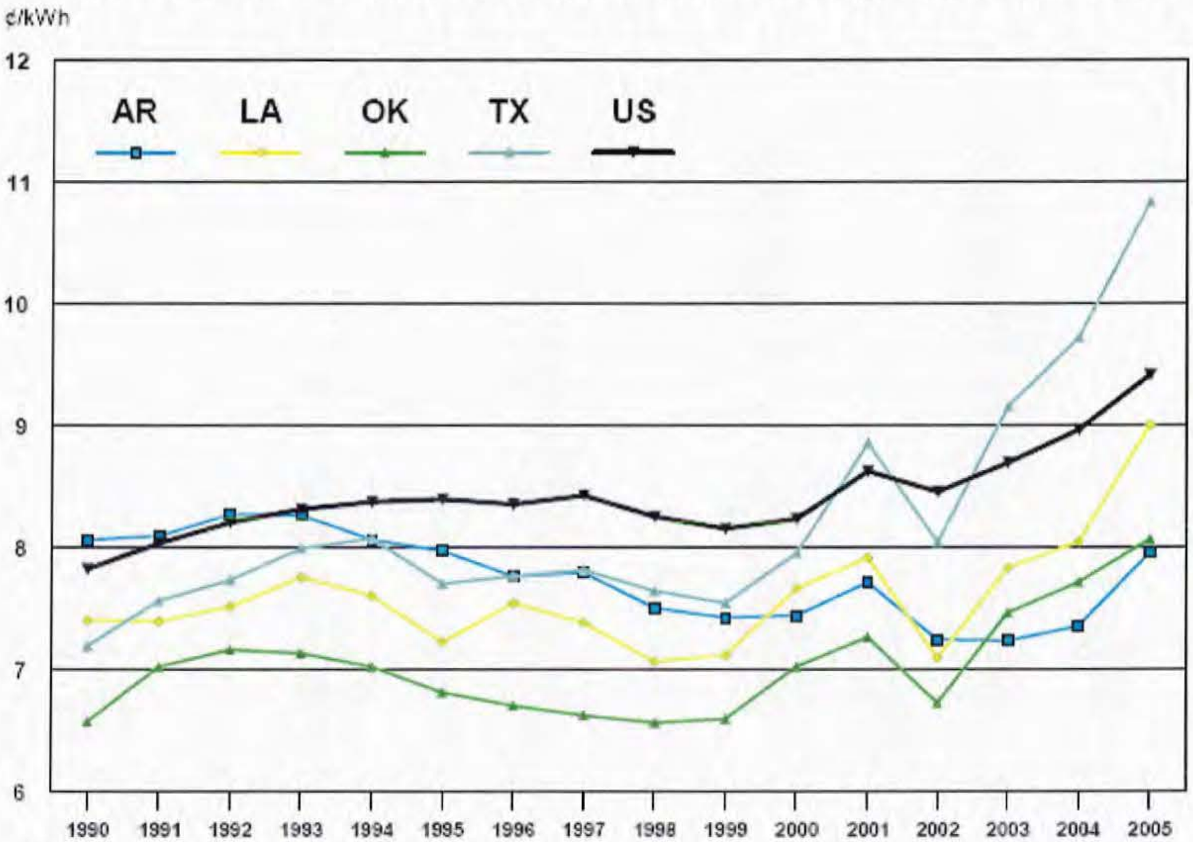


Data Source: DOE/EIA

Mid-South

Texas (in the ERCOT region of the state) is the only state in the four state region that has restructured. Texas residential retail prices were consistently below the national average throughout the 1990s, as Figure 22 shows. However, Texas residential prices have risen considerably from 2002 through 2005, at more than three times the national average percentage increase, almost 35 percent increase versus the national average 11 percent increase during that time span. Prices in Louisiana and Oklahoma have also risen faster that the national average, at 27 percent and 20 percent respectively, but are still below the national average. The region has one of the highest proportion of its generation using natural gas in the country. Texas has 42 percent of its generating capacity and nearly half or the power generated from natural gas in 2003 (49 percent of the total MWh produced in the state), Louisiana is close at 41 percent of its capacity and

Figure 22. Mid-South Residential Average Retail Price

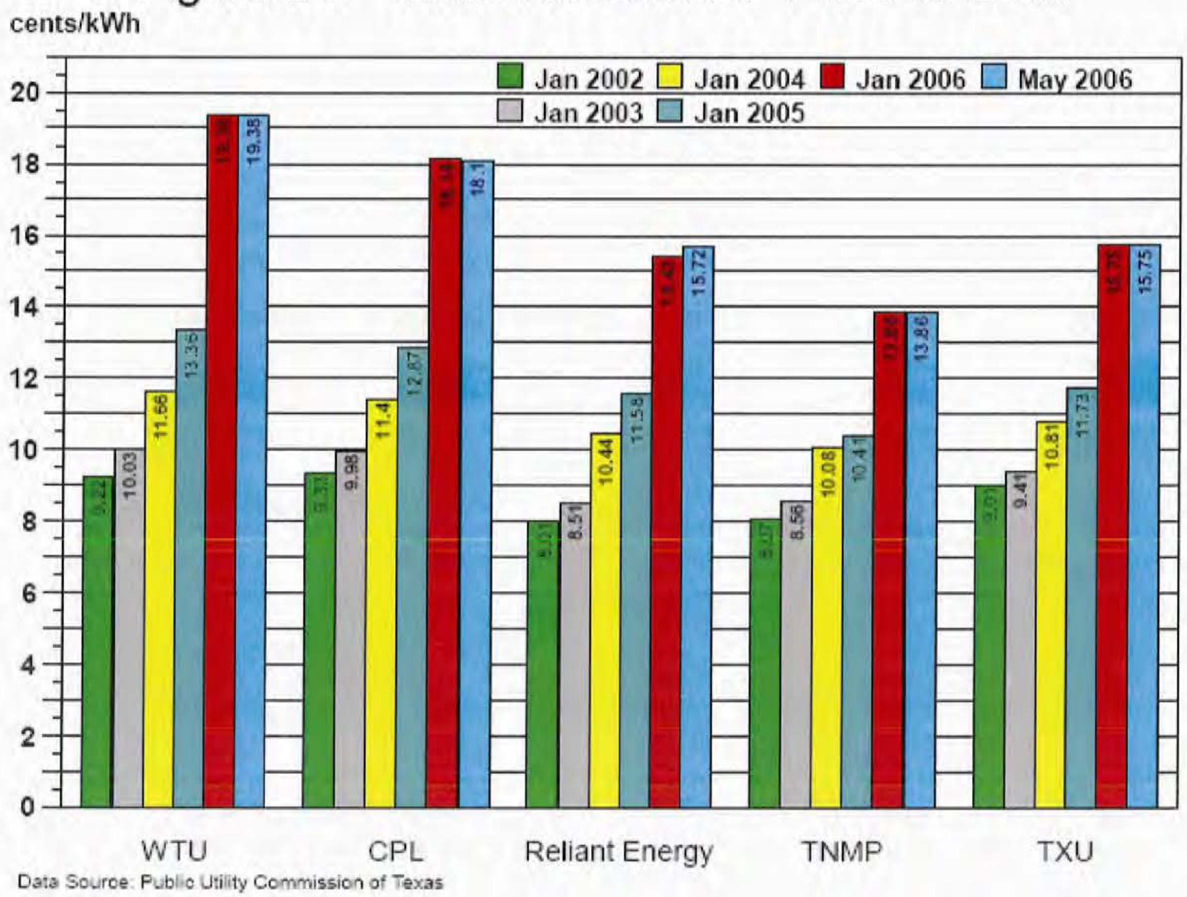


Data Source: DOE/EIA

48 percent of the generation from natural gas, and Oklahoma had 52 percent of its capacity and 36 percent of its generation using natural gas in 2003.[15]

For a closer examination of retail prices in Texas, Figure 23 graphs the "price-to-beat" rates for residential customers from January 2002 to May 2006 in the five Texas service territories with retail access in the state. The price-to-beat is the price used by customers to compare the distribution company price with the price offered by alternative suppliers. The price-to-beat rate is administratively set (not by a competitive procurement process) by the Public Utility Commission of Texas and is adjusted to reflect changes in natural gas and purchased energy market prices. Since retail access began in Texas on January 1, 2002, the residential price-to-beat rates have increased substantially for customers in the five investor-owned companies' service territories in the ERCOT region of the state. Between January 2002 and May 2006, the price-to-beat rates have

Figure 23. Texas Residential "Price-to-Beat"



[15]DOE/EIA, "State Electricity Profiles 2003," April 2006.

increased by almost 72 percent in Texas-New Mexico Power (TNMP), almost 75 percent in TXU Electric & Gas (TXU), 94 percent in Central Power and Light (CPL), over 96 percent in Reliant Energy (Reliant), and over 110 percent in West Texas Utilities (WTU). About 62 percent of residential customers are paying the price-to-beat rate (Figure 3).

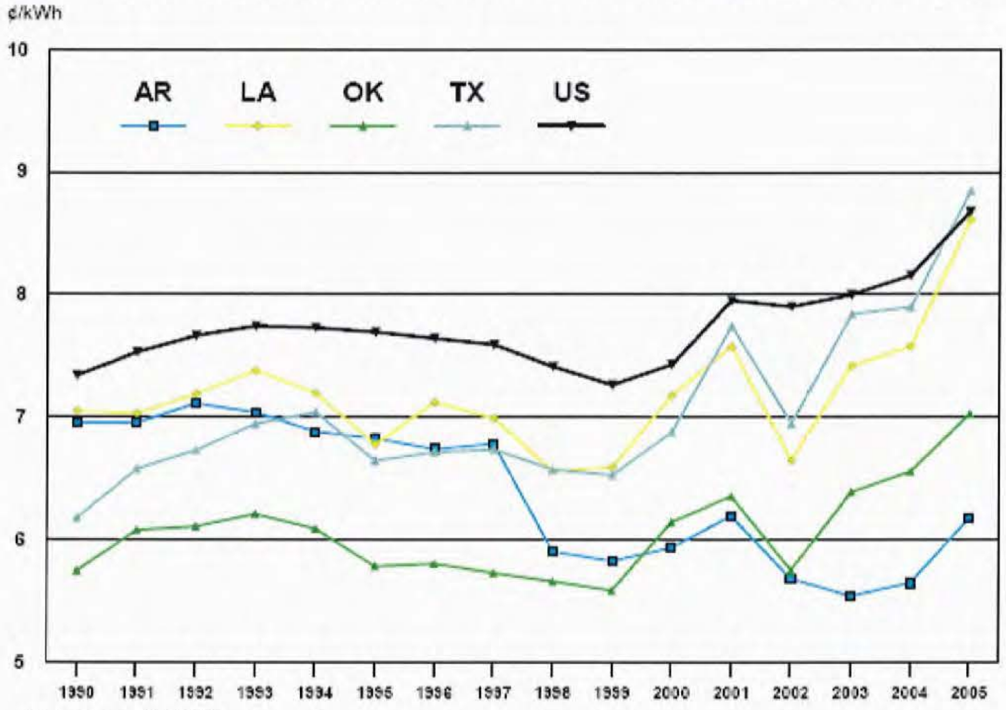
Texas has one of the most active retail markets in terms of residential customers being offered competitive prices. From a survey of offers by the Texas Public Utility Commission,[16] there were six suppliers and seven offers below the price-to-beat in WTU's service area, nine suppliers and 11 offers below the price-to-beat in CPL's service area, 10 suppliers and 10 offers below the price-to-beat in Reliant's service area, four suppliers and five offers below the price-to-beat in TNMP's service area, and eight suppliers and nine offers below the price-to-beat in TXU's service area. However, while these offers are below the current price-to-beat for the respective service area, the best offers are at substantially higher prices than existed when retail access began January 2002. For WTU's service area, the best current offer is 71 percent higher than the January 2002 price-to-beat for customers in the area. The best offer in CPL's area is 56 percent higher than its 2002 price-to-beat, the best offer in Reliant's area is 73 percent higher, the best offer in TNMP's area is 63 percent higher, and the best offer in TXU's area is 54 percent higher.

The pattern is again similar for mid-south commercial customer prices, as shown in Figure 24. The Texas state average price for commercial customers was below the national average from 1990 through 2004, and was just above in 2005. Louisiana also saw a substantial increase since 2002, but remained just below the national average in 2005. Texas commercial customer prices increased by 27 percent from 2002 to 2005, while Louisiana increased 30 percent during that same time period (the national average price increase for commercial customers was just under 10 percent). For industrial customers in the region, as seen in Figure 25, both Texas and Louisiana have been above the national average price for industrial customers from 2003 through 2005. Both states again have had substantial price increases for industrial customers since 2002, 53

[16]Public Utility Commission of Texas, "Retail Electric Service Rate Comparisons," May 2006.

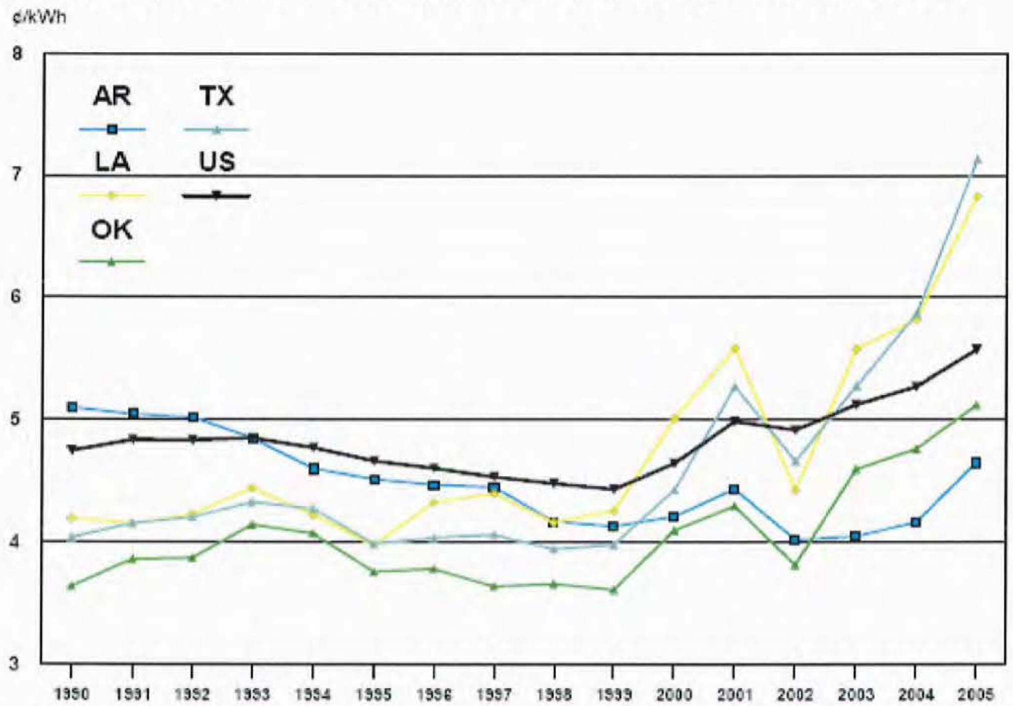
percent Texas in and 55 percent for Louisiana (the national average price for industrial customers increased by 13 percent).

Figure 24. Mid-South Commercial Average Retail Price



Data Source: DOE/EIA

Figure 25. Mid-South Industrial Average Retail Price

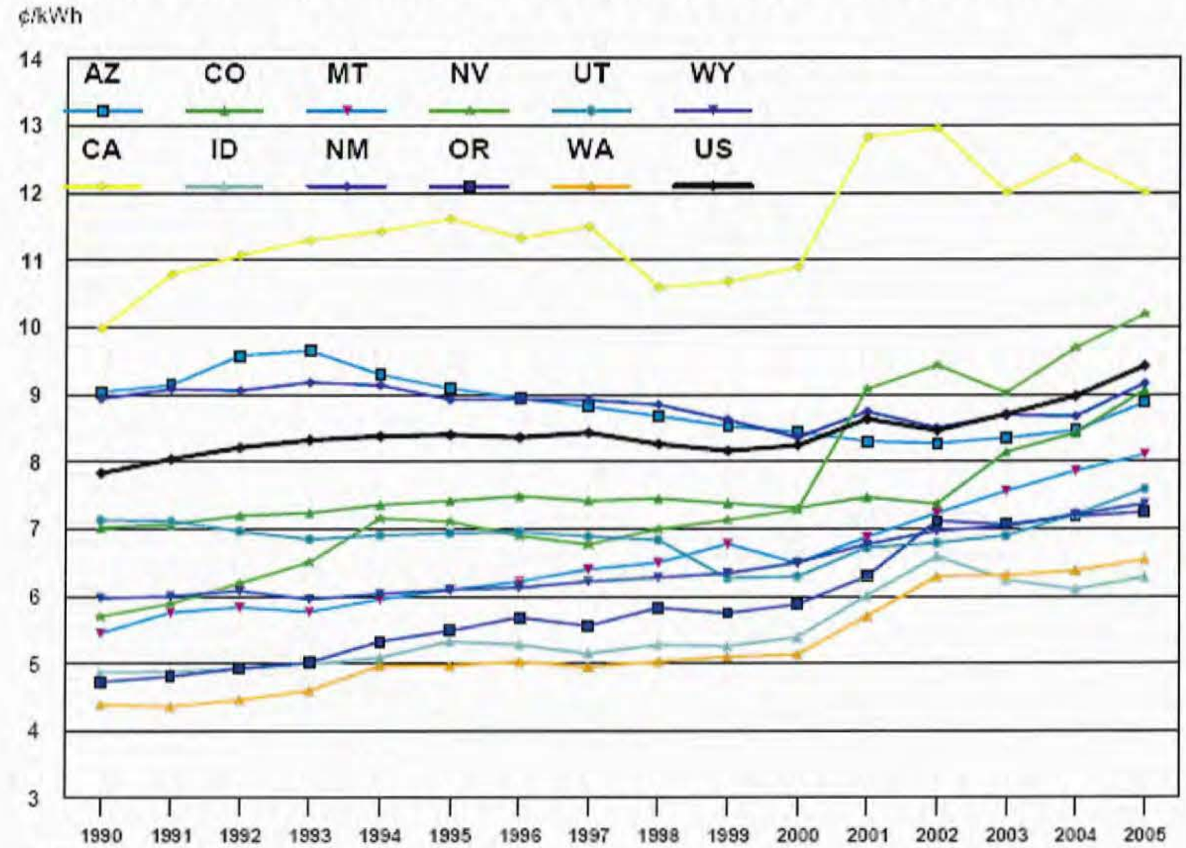


Data Source: DOE/EIA

West

Similar to the Midwest, western residential average state prices were relatively stable from 1990 through 2000, as can be seen in Figure 26. The impact of the western power crisis can be seen from 2001 and in later years across the western states. California, of course, had retail access at the time of the western power crisis, and suspended it September of 2001. Arizona is the only state in the west that continues to have retail access for all customer groups, which began January 1, 2001 (as Figures 2, 3, and 4 show, no retail customers are currently be served by alternative suppliers in the state). Montana began retail access for large customers in 1998 (the same year California began), but has continued to postpone retail access for residential customers. Nevada and Oregon are open for large customers only.

Figure 26. West Residential Average Retail Price

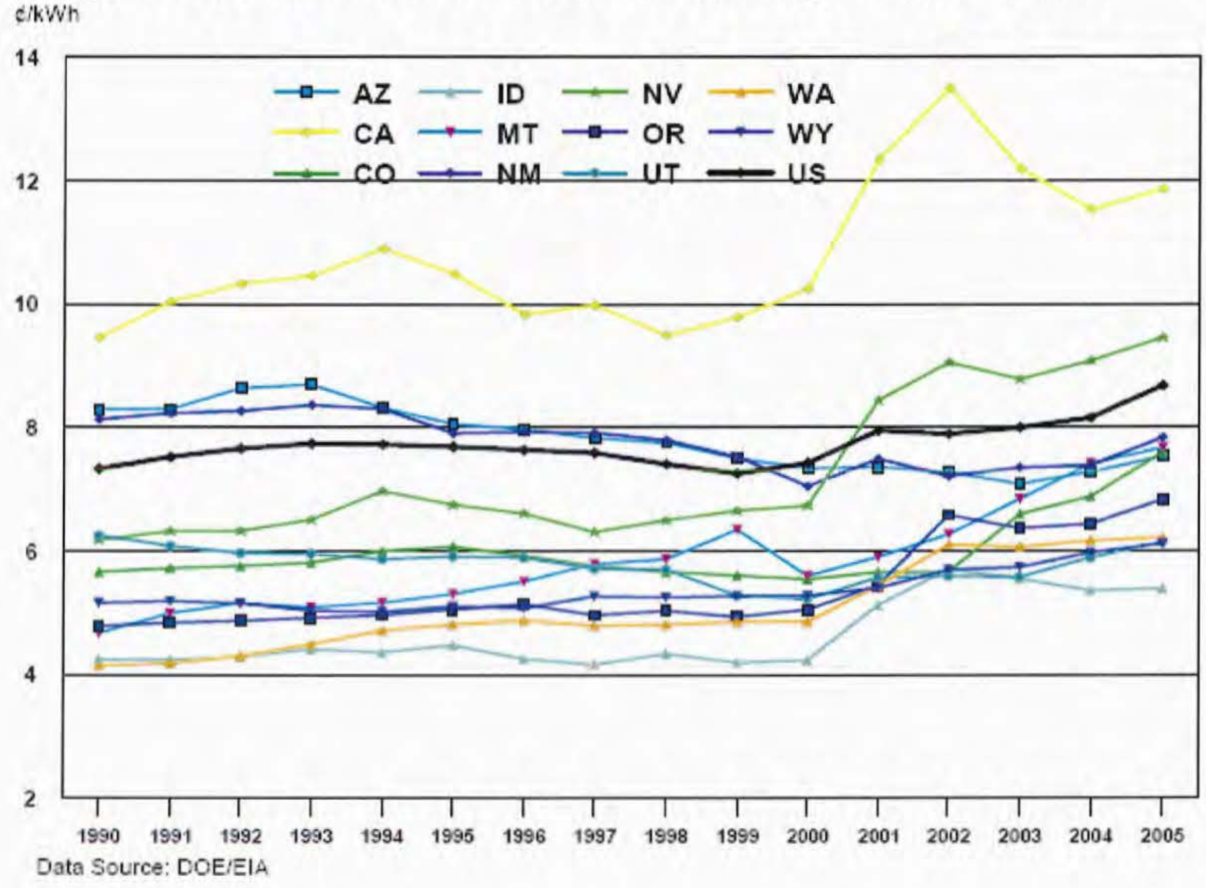


Data Source: DOE/EIA

California has been consistently above the national average throughout the period in Figure 26. The California discount can be seen in 1998 and then the significant price increases in 2001 and 2002 in the aftermath of the power crisis. Prices have leveled off since, but California residential prices remain 27 percent above the national average in 2005. Nevada residential prices have also increased to above the national average, to eight percent above the national average in 2005. All other western states were below the national average in 2005.

A similar pattern can be seen for western commercial customers in Figure 27. California is again consistently above the national average throughout the period and, following the western power crisis, most states in the region saw price increases. California commercial customer prices also declined from the peak in 2002, but remain well above the national average, by almost 37 percent. Nevada also moved above the national average following the crisis, to nine percent above the national average in 2005. All other states remained below the national average, however, Colorado and Montana had significant price increases of 34 percent and 22 percent, respectively, between 2002

Figure 27. West Commercial Average Retail Price

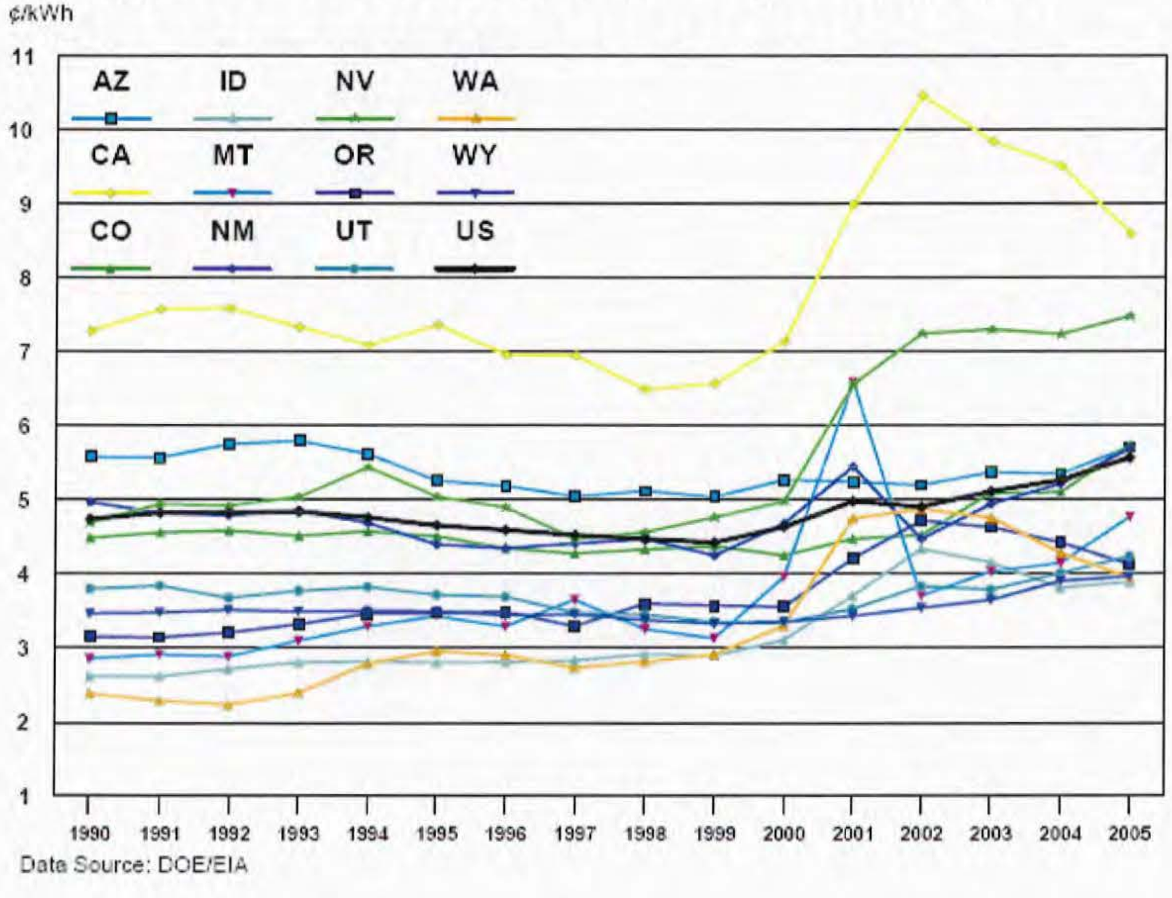


Data Source: DOE/EIA

and 2005 (the national average increase for this customer group was 10 percent for that time period).

Figure 28 shows the industrial customer average prices for the western states. California again was consistently above the national average throughout the period, and saw a 59 percent increase in the industrial customer prices from 1999 to 2002. Then, the price declined, but remained 54 percent above the national average price. Nevada also saw an increase in price for this customer group, with the 2005 average state price at 34 percent above the national average. Montana had a considerable spike in the industrial customer price in 2001, the peak of the western power crisis – the price in 2001 was more than twice the 1999 price. The Montana price dropped back down, but increased by 29 percent between 2002 and 2005. Oregon and Washington had *decreases* in the industrial customer prices of 13 percent and 19 percent, respectively, between 2002 and 2005.

Figure 28. West Industrial Average Retail Price



Data Source: DOE/EIA

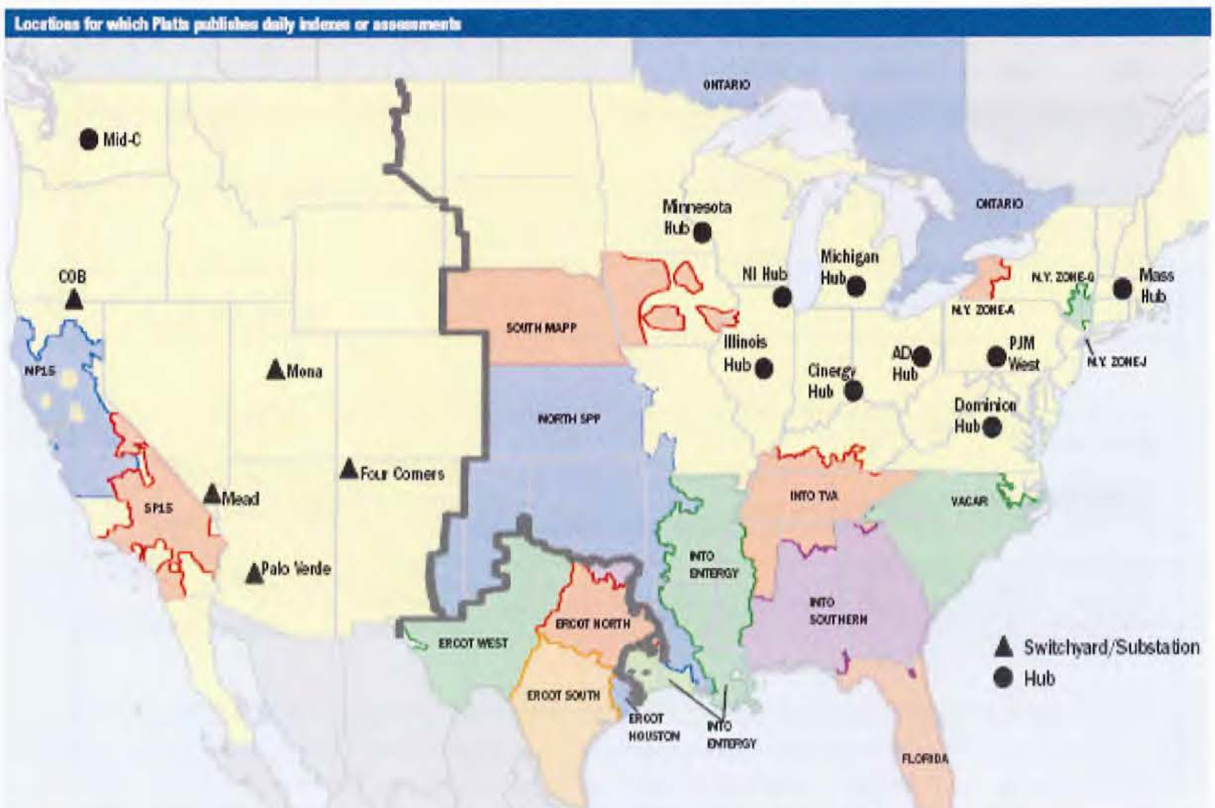
Regional Wholesale Markets

This section reviews eight wholesale electricity regions in the U.S. The country is divided based on markets and/or regional proximity. Some new nodes have been created in some regions or have changed since last year's Performance Review. The regions and hubs examined below are:

1. PJM: PJM, PJM West, AD Hub, Dominion Hub, and NI Hub
2. ISO New England: Mass Hub
3. New York ISO: NY Zone A, NY Zone G, and NY Zone J,
4. MAPP South and Midwest ISO: Michigan Hub, Minnesota Hub, Illinois Hub, and Cinergy Hub
5. VACAR, Southern, and Florida
6. TVA, Entergy, SPP North
7. Texas
8. West: Mid-Columbia Hub, CA-OR Border, NP15, SP15, Mead, Palo Verde, Four Corners, and Mona Utah.

These regions, hubs, or substations are shown in Figure 29.

Figure 29. Map of selected U.S. electricity hubs

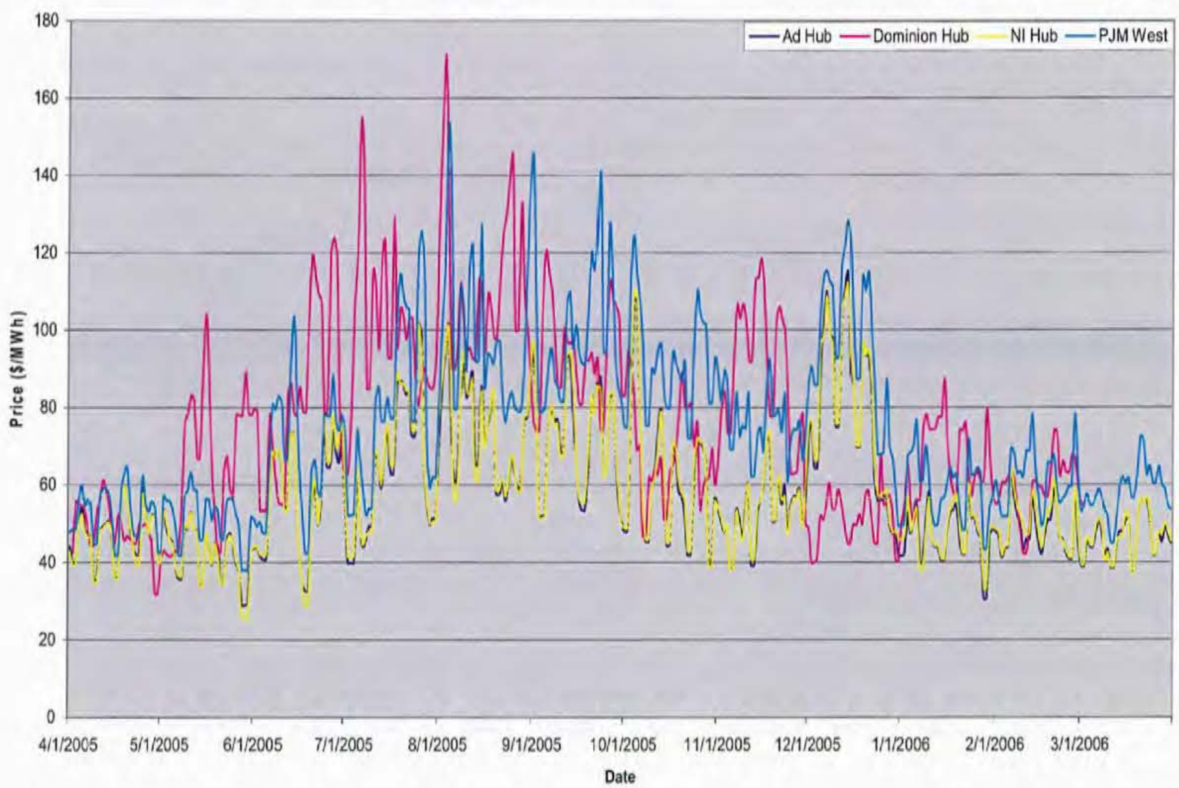


Source: Platts at http://www.platts.com/Oil/Resources/Glossaries/

PJM

Figure 30 shows the daily average peak hour prices for hubs within PJM. The Dominion Hub (in the Commonwealth of Virginia) entered PJM on May 1, 2005. Prices of the hubs varied greatly over the time period examined. They ranged from a high of \$170/MWh (August 3, 2005 at the Dominion Hub) to a low of \$25.25/MWh (May 30, 2005 at the NI Hub), with most prices being within a \$40 to \$80 range. Noticeable peaks can be seen at the time of Hurricanes Katrina and Rita. The price fluctuations seemed to subside slightly thereafter, but not until the beginning of 2006. The NI Hub and the AD Hub tended to have the lowest prices and were highly correlated with one another. When Dominion entered PJM, the prices at that hub seemed to be negatively correlated with the other hubs. Prices at the Dominion Hub were generally higher than other hubs within PJM from May 1, 2005 until September 1, 2005. Clear examples of this can

Figure 30. Daily Average Peak Hour Prices for Hubs within PJM

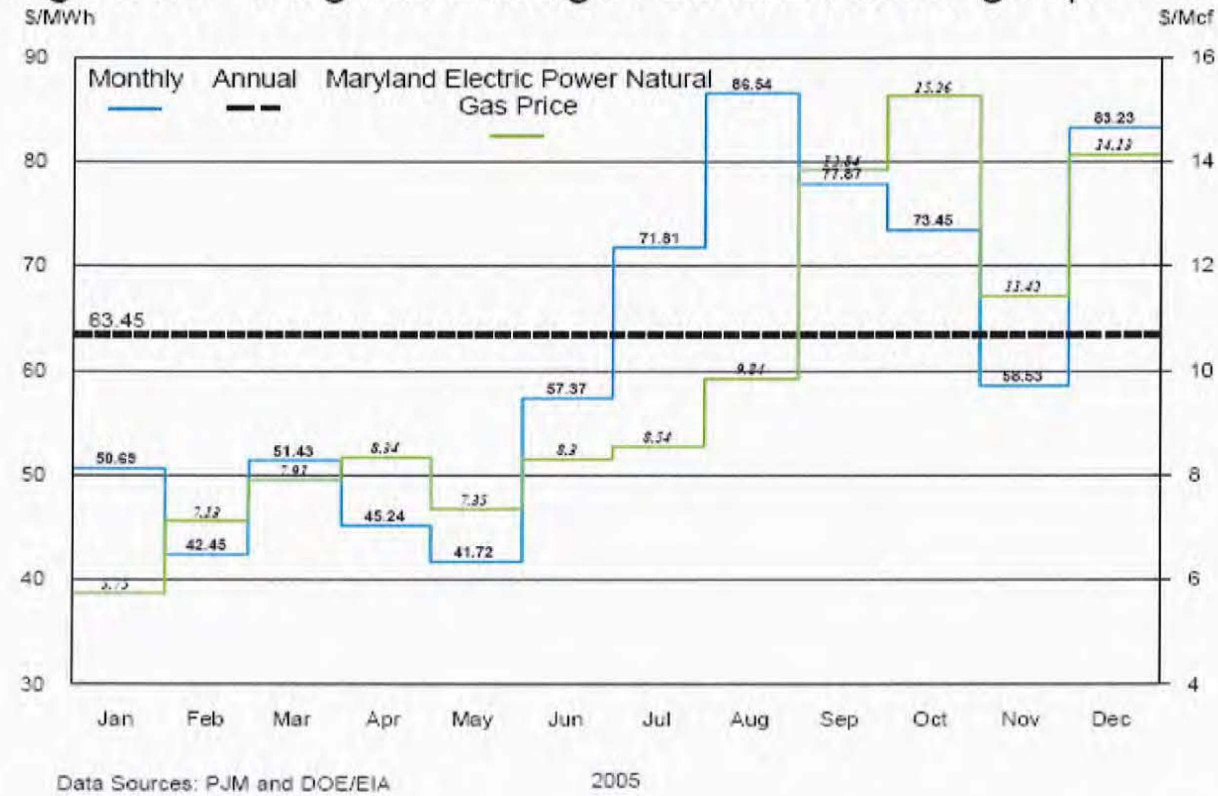


Data Source: Platt's *Megawatt Daily*.

be seen through the end of June 2005. At that time, the prices at the Dominion Hub began to follow the other nodes at least in direction, and eventually with respect to price levels. Price spikes occurred at the Dominion Hub in the May, June, and July. Price spikes occurred in the other three hubs in December, while the Dominion hub remained lower.

Figure 31 compares the weighted-average PJM day-ahead market price with monthly average natural gas prices in 2005.[17] Natural gas prices rose sharply in September and October, in the wake of the hurricanes, however, power prices were increasing throughout the summer months and reached the annual peak in August. PJM power prices actually fell September through November and climbed again in December. This suggests that warm weather in the PJM region had an impact on power prices before natural gas prices began their record climb.

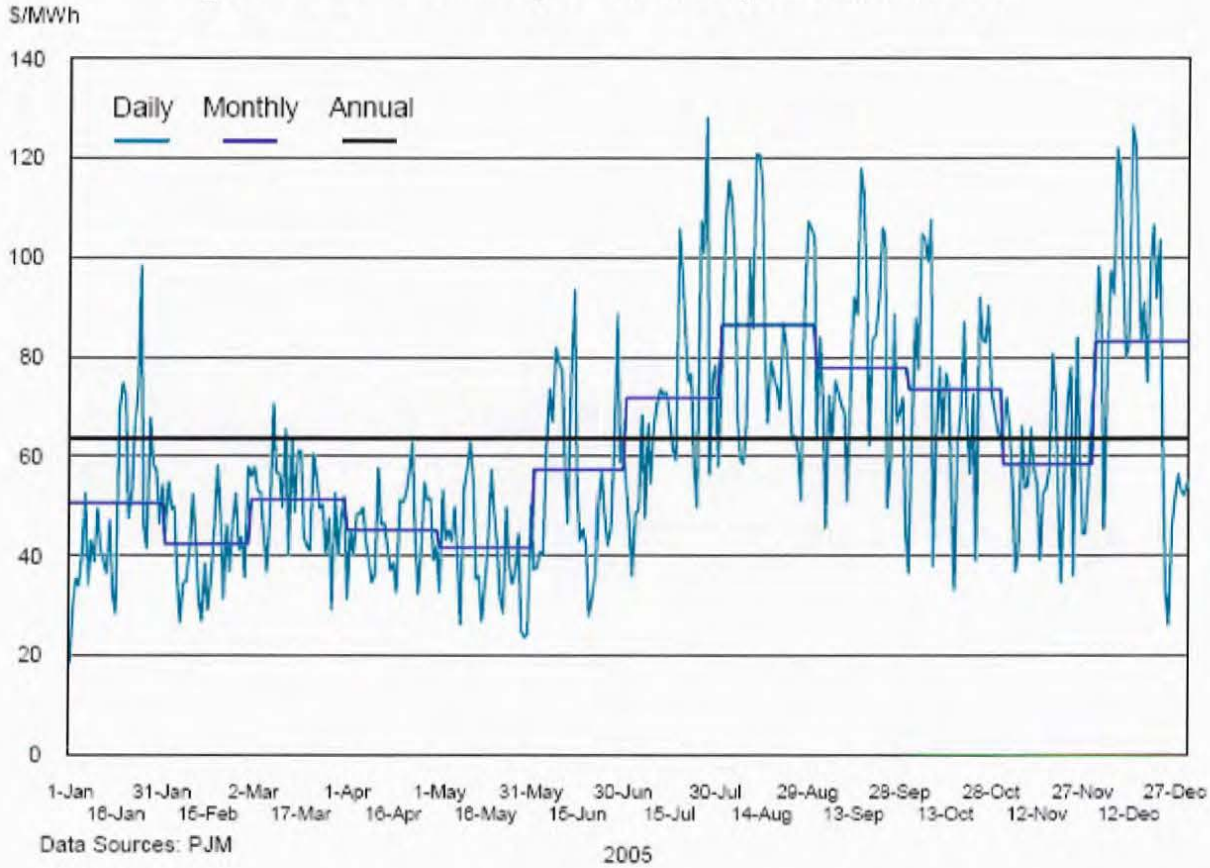
Figure 31. Weighted average PJM and natural gas prices.



[17] All references to natural gas prices refer to the EIA-DOE "Electric Power Price." These prices can be found at http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

Figure 32 shows the PJM weighted-average again with the weighted-average daily price in the PJM day-ahead market. As can be seen in the figure, the market became more volatile in about June and continued throughout the rest of the year. Figure 30 shows that price volatility abated in early 2006.

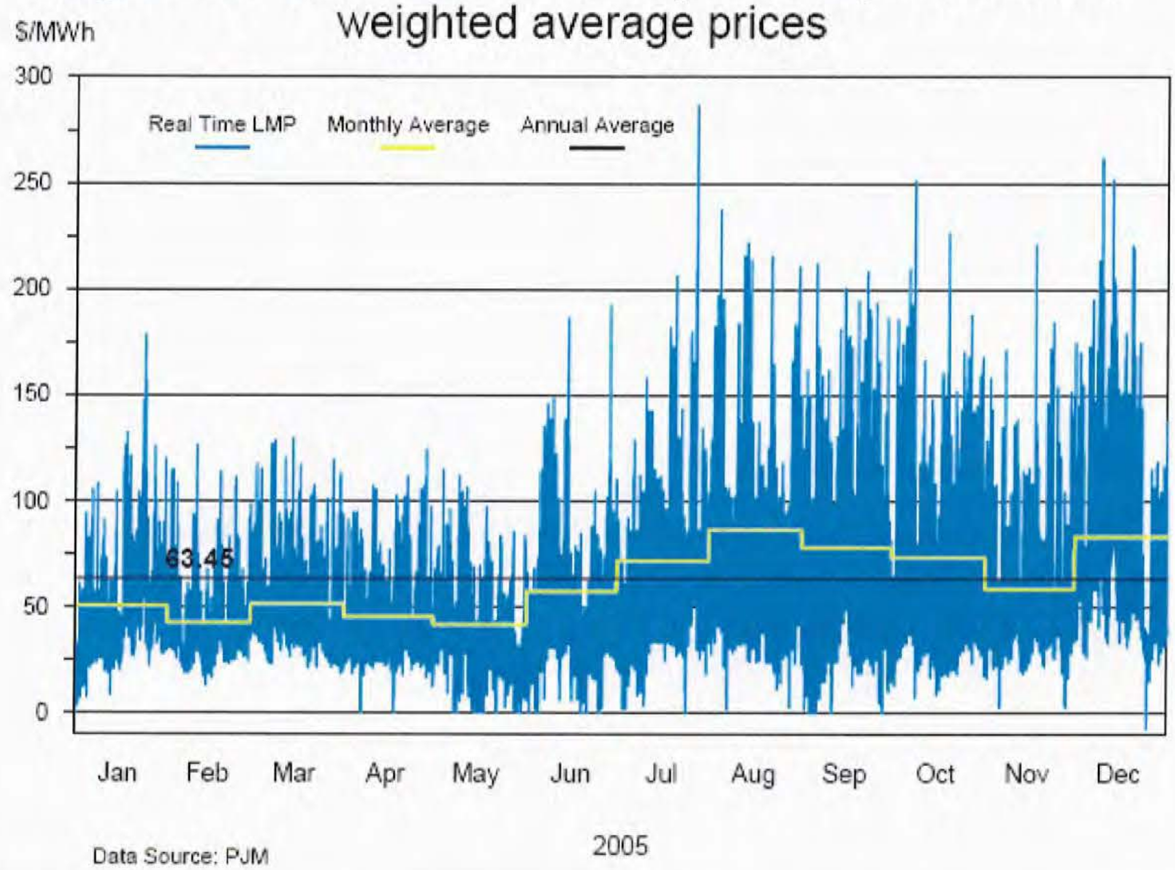
Figure 32. Monthly and Daily PJM Prices.



Data Sources: PJM

The price volatility in the second half of the year can be seen more vividly in Figure 33 that shows real-time hourly prices, along with the weighted-average monthly prices and the annual weighted-average price. Hourly prices well above $100/MWh were common, again before natural gas prices reached their record levels.

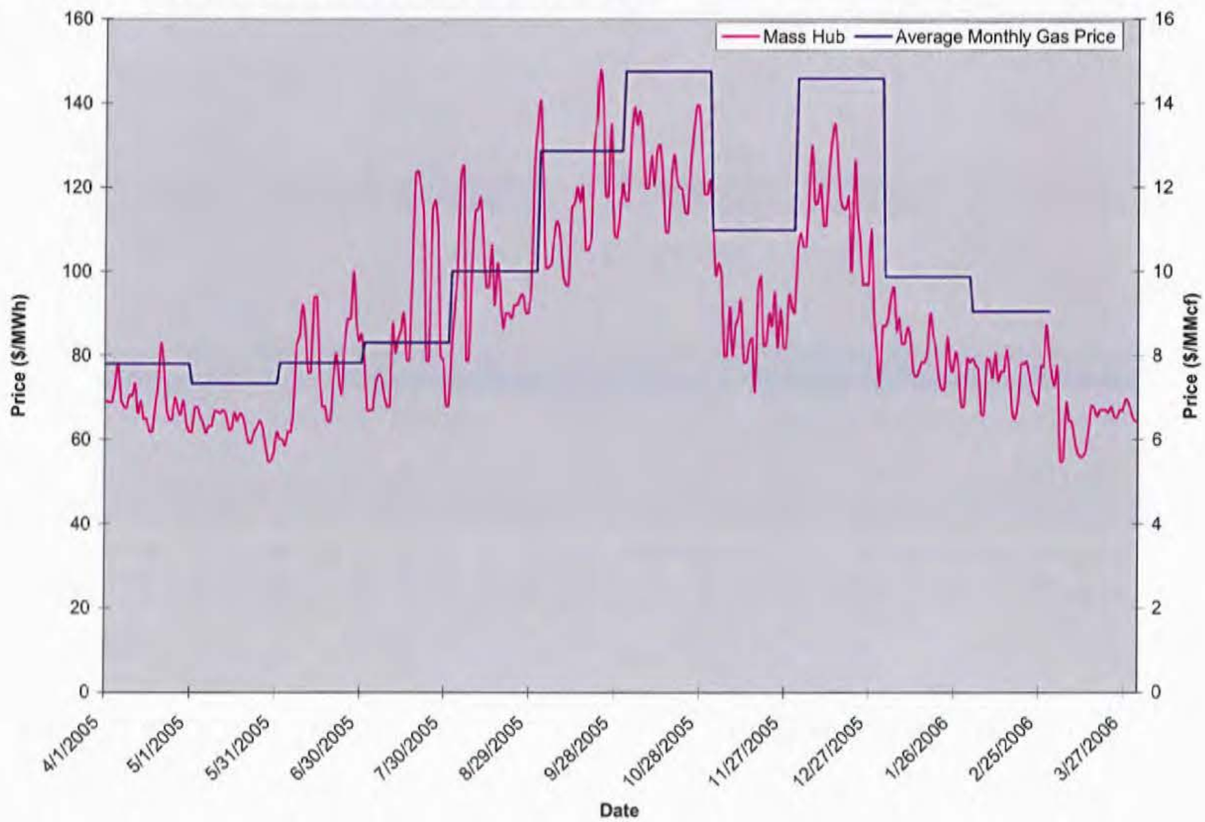
Figure 33. PJM real-time hourly, monthly and annual weighted average prices



ISO New England: Mass Hub

Figure 34 shows the daily average peak hour prices for the Mass Hub in ISO New England and the monthly average natural gas prices. Wholesale electricity prices ranged from a high of $148/MWh (September 22, 2005) to a low of $55/MWh (May 27, 2005 and March 5, 2006). With rare exceptions, prices remained above $100/MWh from the end of August to the start of November. As with PJM prices, New England power prices increased and became more volatile during the summer of 2005, before the natural gas price increases. However, the power prices are more closely correlated with natural gas prices. This is likely a result of the higher proportion of New England natural gas generation. The impact of the hurricanes on natural gas and power prices can be seen in the fall months of 2005. The increase in electricity prices in late January can be attributed to increased demand for natural gas for heating in addition to electricity generation which led to higher natural gas prices.

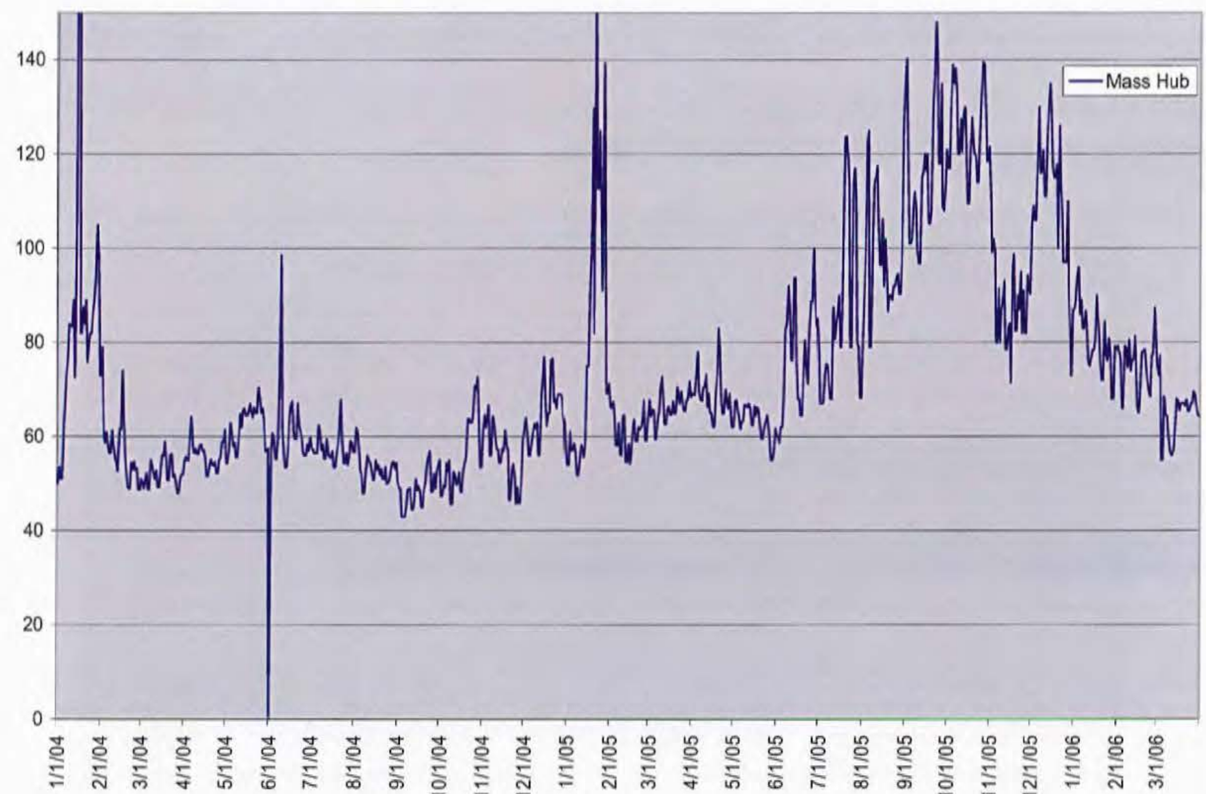
Figure 34. Daily Average Peak Hour Prices for Mass Hub and Monthly Average Natural Gas Prices



Data Source: Platt's *Megawatt Daily* For MA Hub, EIA-DOE for natural gas prices.

Figure 35 extends that time frame to examine the price path back to the start of 2004. The graph shows greater variability in the wholesale electricity price in 2005 as compared to 2004. It also shows prices to be reasonably stable in the summer months, but showing greater volatility during the winter months. This volatility has increased over time. The Mass Hub saw higher prices in the winter of 2005-2006 than for the winter of 2004-2005. These higher prices were also sustained for a longer period of time.

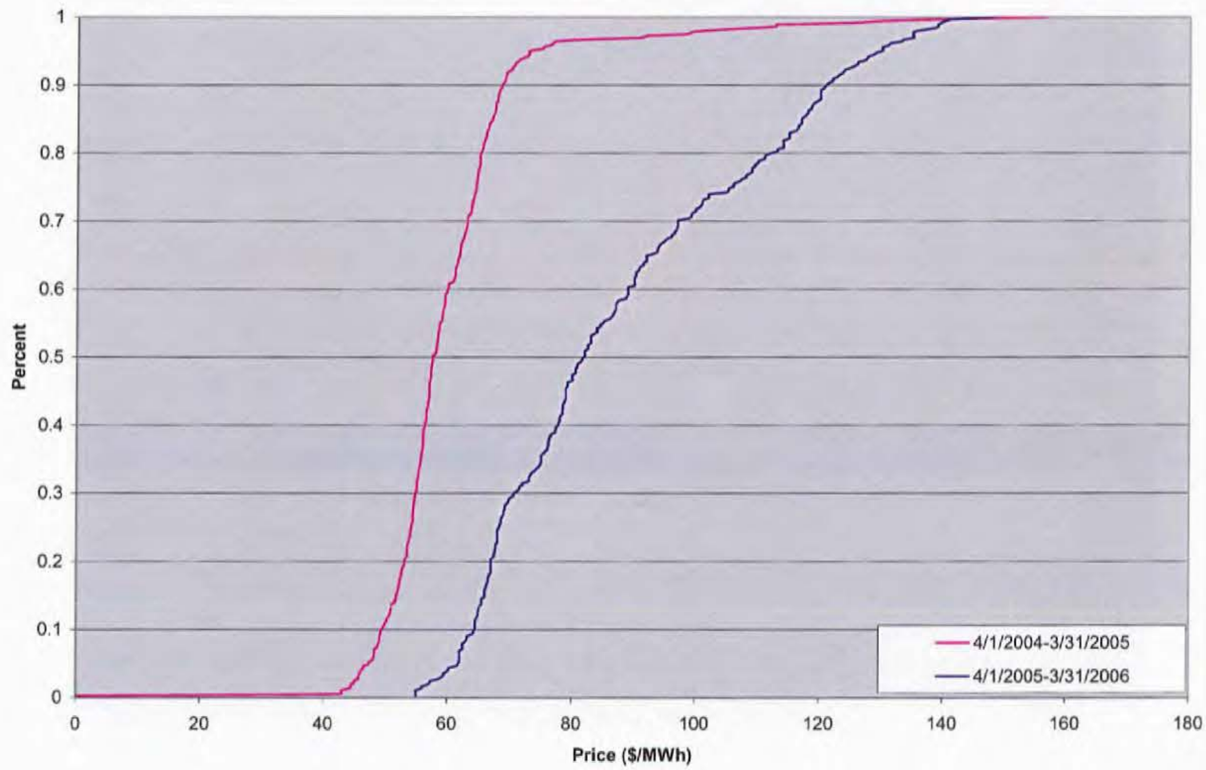
Figure 35. Daily Average Peak Hour Prices for Mass Hub from 1/1/2004 through 3/31/2006



Data Source: Platt's *Megawatt Daily*.

Figure 36 compares the price duration curve from April 2004 through March 2005 with April 2005 through March 2006. The price duration curve shows what percent of time the price was at a given level. For example, 50 percent of the time the price at the Mass Hub was at or below $82/MWh between April 2005 through March 2006. This graph shows that the median price at the Mass Hub increased just over 40 percent in the last year. The price at the 75 percent level increased from $64/MWh to $106/MWh, or a 65 percent increase. At the 25 percent level, prices increased from $54/MWh to $68/MWh, a 26 percent increase.

Figure 36. Price Duration Curves for Mass Hub

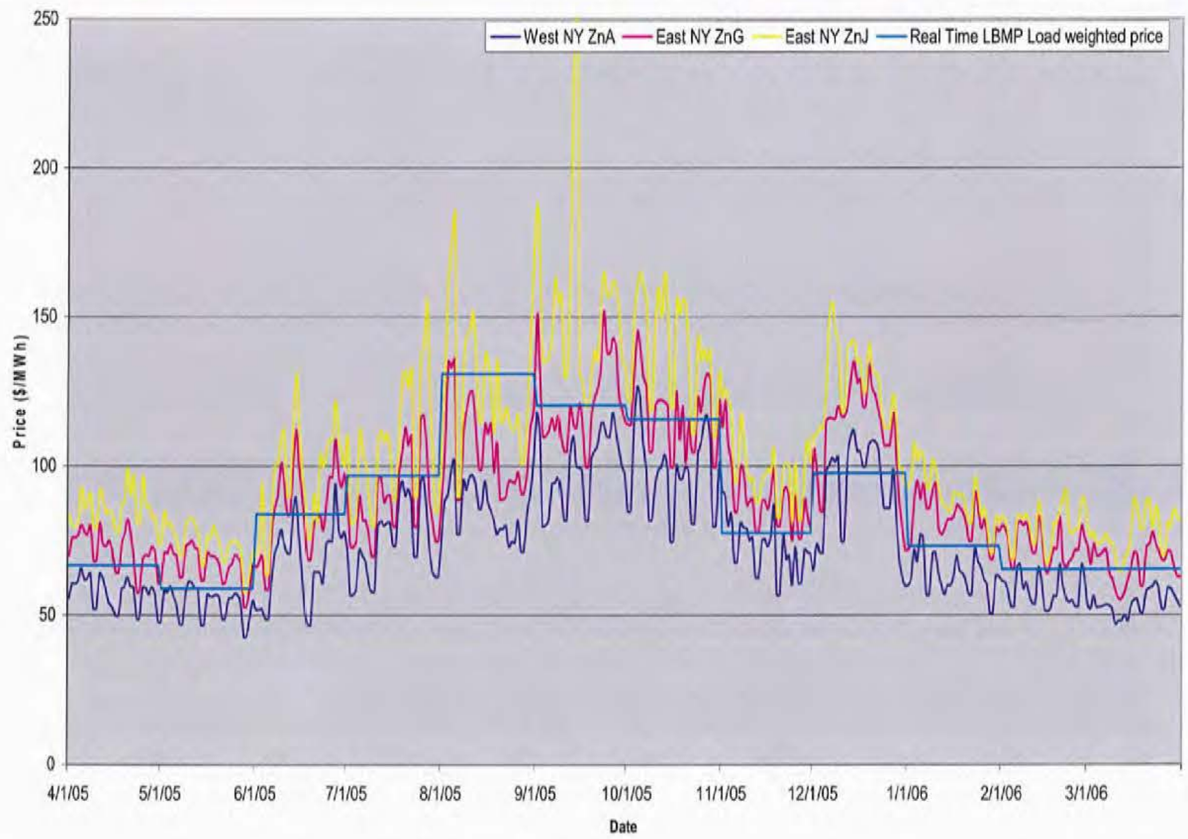


Data Source: Platt's *Megawatt Daily*.

New York ISO: NY Zone A, NY Zone G, and NY Zone J

Figure 37 shows the daily average peak hour prices for the three zones in the New York ISO. The three zones used for this comparison are Zones A, G, and J as well as the real-time Location Based Marginal Price (LBMP) load weighted price. Zone A is the western most region of New York state and includes Buffalo and to the south and west of Buffalo. Zone G is the Hudson Valley region just to the north of New York City. Zone J is the New York City area. These three regions represent three different levels of load and congestion.

Figure 37. Daily Average Peak Hour Prices for New York Zones A, G, and J, and Monthly Load weighted LBMP

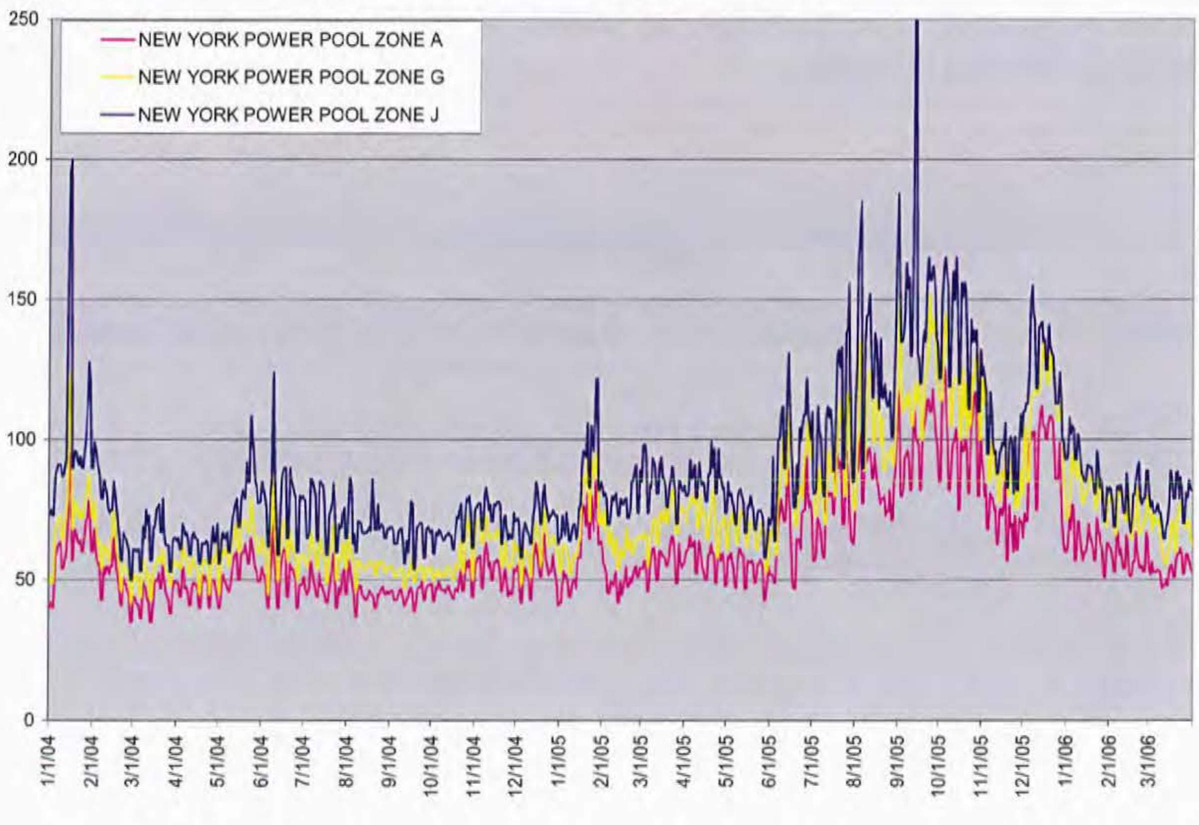


Data Source: Platt's *Megawatt Daily* NYISO for Day-ahead and Real-time prices.

The graph shows that prices in all three regions generally move together. The peaks and valleys are similar in direction, but differ in magnitude. The prices in Zone J are always the highest, while the prices in Zone A are always the lowest. As with PJM and New England, there is an evident shock caused by Hurricane Katrina and the resulting impact on natural gas prices. However, the same cannot be said for a shock from Hurricane Rita. The spike seen in mid-June, when prices soared to $250, occurred before natural gas prices increased and, therefore, cannot be explained by natural gas prices. After high electricity prices through months that are typically off-peak periods, prices have returned to the level at which they started the period.

Figure 38 extends the time frame examined to show wholesale prices for the three zones from January 2004 through March 2006. Though prices seem to be

Figure 38. Daily Average Peak Hour Prices for New York Zones A, G, and J from 1/1/2004 through 3/31/2006

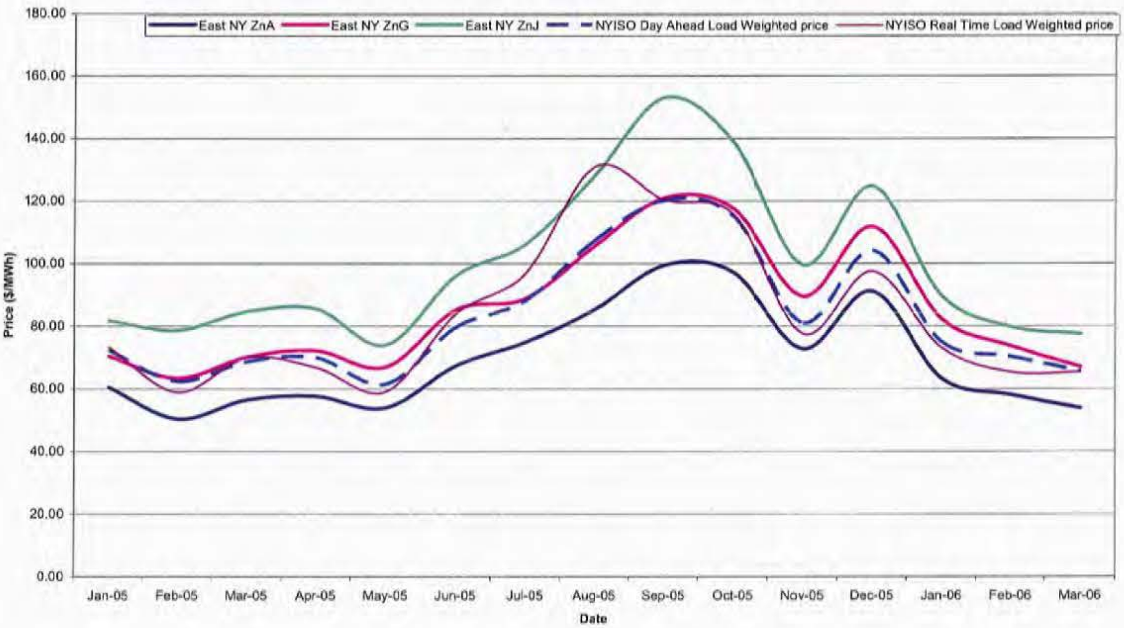


Data Source: Platt's *Megawatt Daily*.

generally fluctuating within a $20/MWh price range for any given region for most of the year, the spikes, particularly in the later part of 2005, are much higher and more sustained than at any other time in 2004. As discussed above, part of this result is likely due to higher natural gas prices. However, it is unlikely that high natural gas prices explain all of this price variation.

Figure 39 shows the average monthly prices ($/MWh) for Zones A, G, and J and the day-ahead and real-time load weighted prices. The graph shows the increases in price from July through October. After October prices drop for November, rebound in December, and fall again from January until the end of the time period examined. Zone G tends to be very close to the day-ahead average volume weighted average prices for the entire period examined. In August 2005, the ISO real-time load weighted price exceeded the prices in the trading zones.

Figure 39. Monthly Average Peak Hour Prices for New York Zones A, G, and J, and Monthly Load weighted LBMP (Real-Time and Day-Ahead Prices)

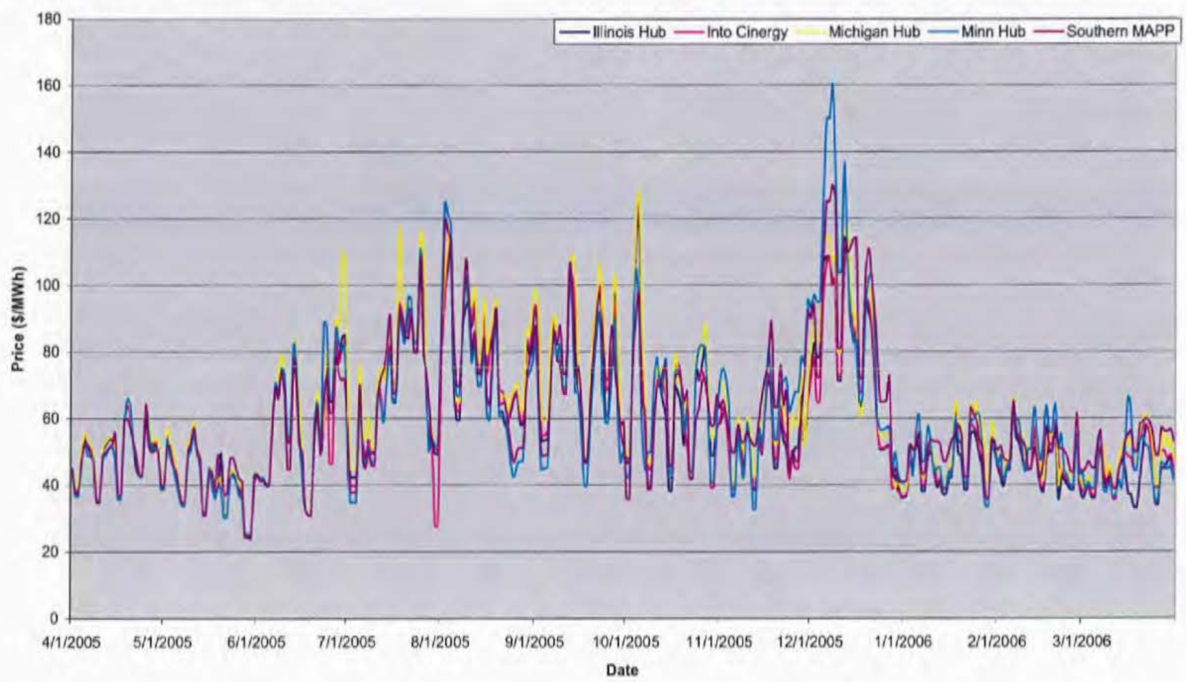


Data Source: Platt's *Megawatt Daily* for Zonal prices, NYISO for Day-ahead and Real-time prices.

MAPP South and Midwest ISO

Figure 40 shows daily average peak hour prices for the four new MISO trading hubs as well Southern MAPP. MISO introduced four standard trading hubs beginning April 1, 2005. The prices of the MISO hubs are highly correlated with one another, as well as correlated with Southern MAPP. Prices showed considerable volatility in MISO and Southern MAPP, particularly between June and December 2005. Prices generally ranged in the \$50/MWh to \$90/MWh range, but hit a low \$28/MWh (July 31, 2005, into Cinergy) and a high of \$160/MWh (December 8, 2005, Minnesota Hub). With the amount of price volatility in the region, the impacts of Hurricanes Katrina and Rita are not perceptible. Prices began to climb in all areas in late November, peaked in early December, and returned to prices in the \$40/MWh to \$60/MWh range which is similar to the prices seen at the beginning of the period examined. The price increase in December is likely due, at least in part, to high natural gas prices.

Figure 40. Daily Average Peak Hour Prices for Southern MAPP and MISO Hubs

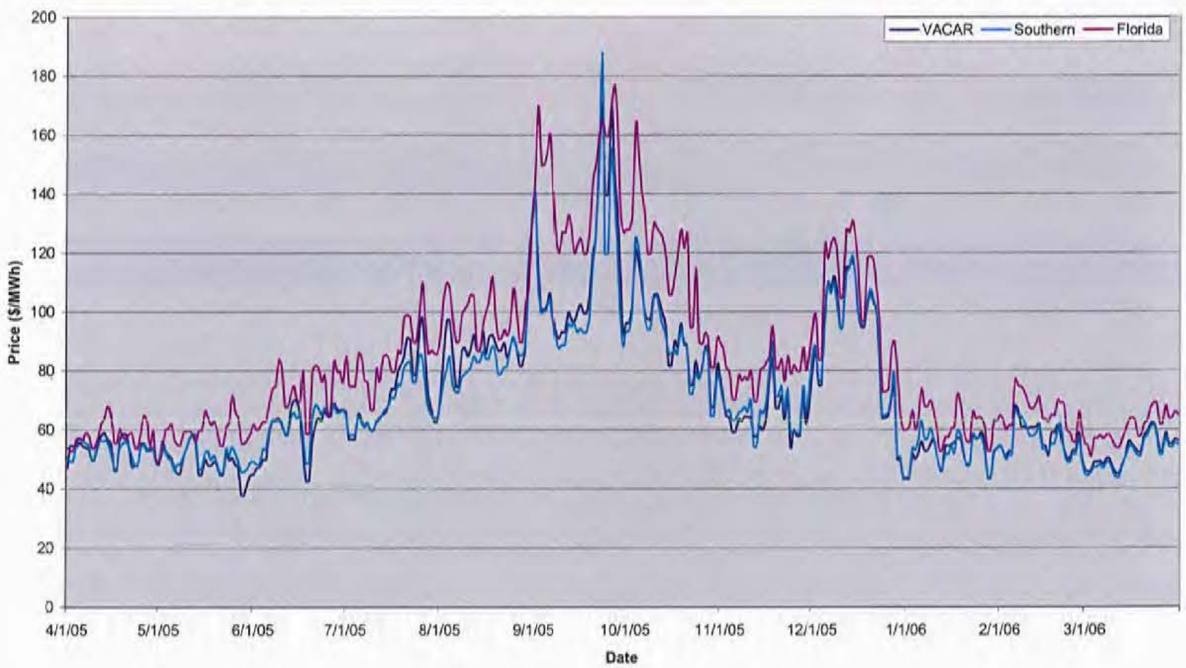


Data Source: Platt's *Megawatt Daily*.

VACAR, Southern, and Florida

Figure 41 shows the daily average peak hour prices for VACAR, Southern Co., and Florida. Florida generally showed the highest prices in any of the three areas shown in the figure. Though prices started in the $50/MWh to $60/MWh range in March 2005, prices rose steadily until September 2005. The two main spikes in 2005 were again likely in response to Hurricanes Katrina and Rita's impact on natural gas prices. All prices in this region tended to move together. After these spikes, prices began to decline until December 2006, where prices reached another brief spike before returning to a range of $60/MWh to $70/MWh. Florida saw prices in excess of $100/MWh from early September through mid October. The price spike in December is not fully explained by natural gas price increases -- since the monthly average natural gas price was lower in December than it was in November or January for Florida.[18]

Figure 41. Daily Average Peak Hour Prices for VACAR, Southern Co, and Florida



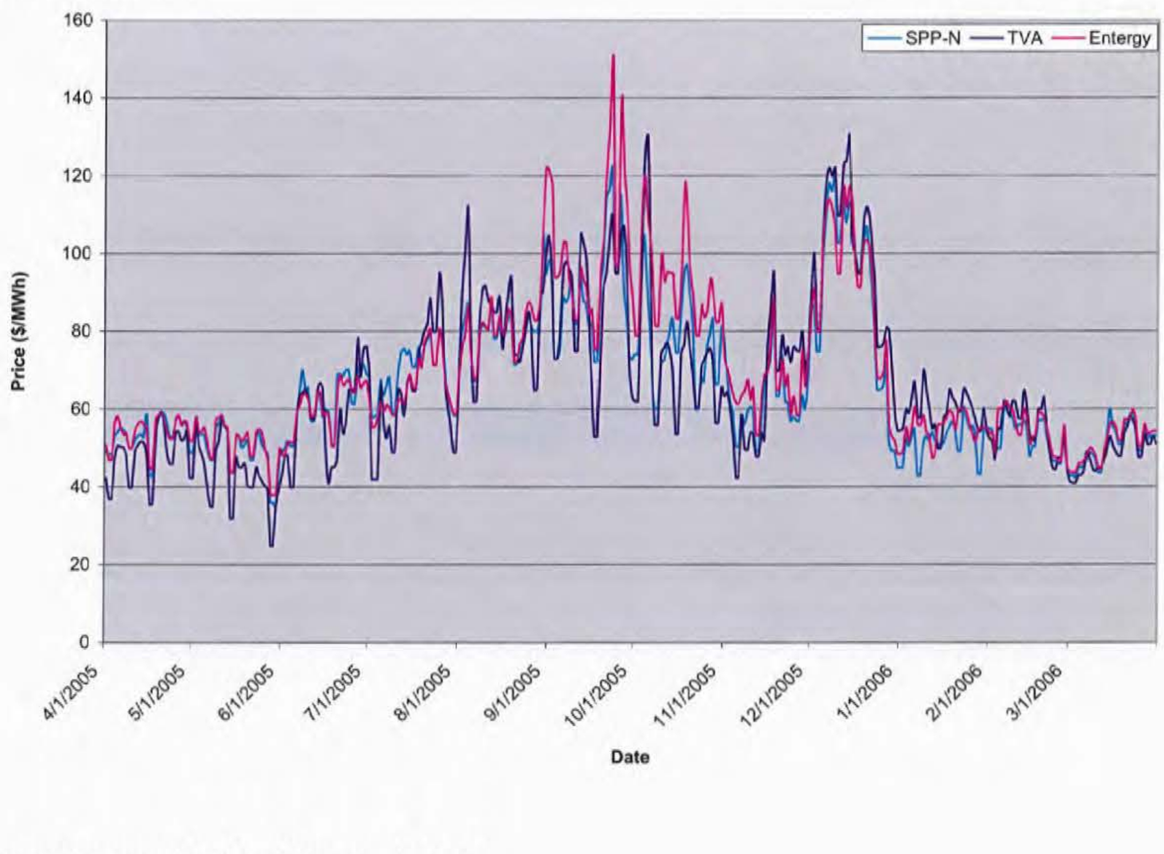
Data Source: Platt's *Megawatt Daily*.

[18] http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SFL_m.htm

TVA, Entergy, SPP North

Figure 42 shows the daily average peak hour prices for TVA, Entergy, and SPP North. Prices across the three regions tended to be correlated. Prices showed high volatility in the second half of 2005, ranging generally from \$50/MWh to \$100/MWh. Spikes in September and October can again be attributed to a response to Hurricanes Katrina and Rita. Natural gas prices were slightly higher in December and may account for some of the power price increase at that time. Prices stabilized in the first quarter 2006, staying in the \$40/MWh to \$60/MWh range.

Figure 42. Daily Average Peak Hour Prices for SPP North, TVA, and Entergy

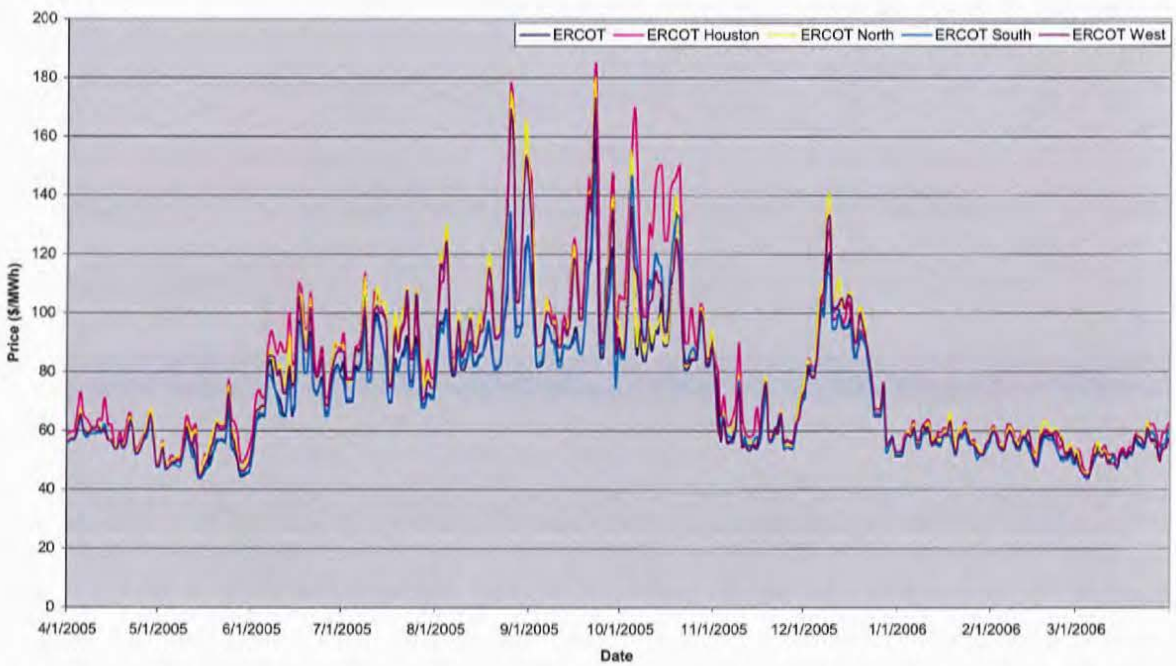


Data Source: Platt's *Megawatt Daily*.

Texas

Figure 43 shows the daily average peak hour prices for five ERCOT trading zones. The prices for all zones are correlated with one another and move in unison. Prices started in the $60/MWh range for the second quarter of 2005, but increased to the $80/MWh to $100/MWh range in the third quarter. Prices increased again in the forth quarter as Texas dealt with a near miss from Hurricane Katrina and a direct hit from Hurricane Rita. The resulting power price spikes can be seen in late August and September. The spike in December can be explained, at least in part, by higher natural gas prices. Wholesale electricity prices stabilized in the first quarter of 2006, returning to the $50/MWh to $60/MWh range.

Figure 43. Daily Average Peak Hour Prices for ERCOT Trading Zones

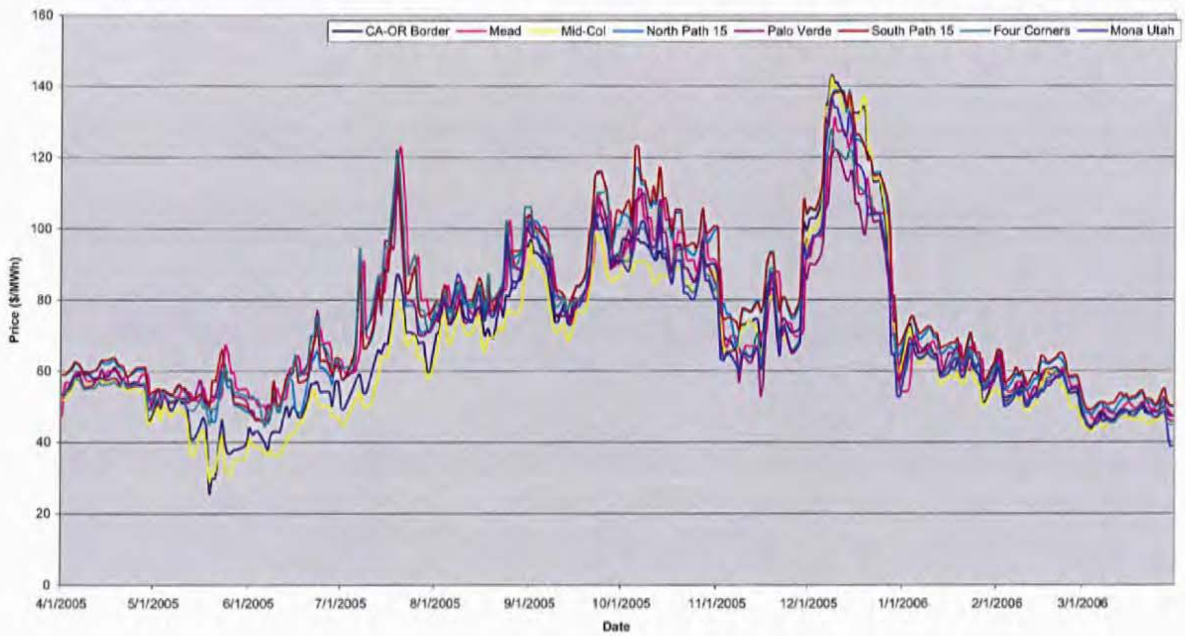


Data Source: Platt's *Megawatt Daily*.

West

Figure 44 shows the daily average peak hour prices for eight western substations. The prices are correlated with each other to a high degree, but not perfectly. Prices started slightly downward for the second quarter of 2005 before starting a steady ascent during the peak summer months. The second quarter of 2005 showed prices in the \$40/MWh to \$60/MWh range, with prices as low as \$25/MWh. Prices in the third quarter stayed closer to \$70/MWh to \$80/MWh. There is a significant price spike in mid-July. The price spike in December is likely a result of natural gas price increases. California saw monthly average natural gas prices increase from \$9.45 per thousand cubic feet in November to \$11.65 in December. The West has seen prices stabilize and decrease in the first quarter of 2006 and prices have returned to the \$40/MWh to \$50/MWh range.

Figure 44. Daily Average Peak Hour Prices for Western Substations



Data Source: Platt's *Megawatt Daily*.

Summary

The impact of hot summer weather and the major hurricanes that hit the Gulf States in 2005 (and the subsequent impact on natural gas prices) resulted in the power price spikes that occurred nearly nationwide. The higher natural gas prices of December were also apparent in the country as a whole. In last year's Performance Review, wholesale power prices above $100/MWh were a rare occurrence. However, in the past year, wholesale electricity prices over $100/MWh were much more common. For example, as shown in Figure 36, at the Mass Hub, 28 percent of the hours from April 2005 through March 2006 saw wholesale prices greater than $100/MWh. This compares to less than two percent at those levels for the twelve months prior to April 2005. Regions such as the Midwest (MISO), and Southeast (Florida, Southern Co.) were seeing wholesale prices over $100/MWh for the first time in several years. However, most regions have seen prices stabilize back to ranges that coincide with the prices at the beginning of the period examined.[19]

[19]While this report is being completed, higher prices are again occurring from high summer temperatures in several regions of the country.

Part B

Retail Market Evaluation and Wholesale Market Conditions

Retail Market Evaluation

To further examine state retail markets, a comparison is made with the state bidding and auction price results and the wholesale market in the mid-Atlantic area. Also in this section, a comparison is made of the retail price trends in restructured and non-restructured states.

Figure 45 combines the mid-Atlantic bidding and auction results shown in the bar chart of Figure 8 with the PJM wholesale market prices in 2005 shown in Figure 31. The stair-step line is the monthly weighted-average PJM prices (real-time LMPs). The light-gray dashed line (constant at $44.34) is the weighted-average annual price in PJM for 2004 and the black dashed line (constant at $63.45) is the weighted-average annual price in PJM for 2005. The various color horizontal lines in the graph are the bidding and auction prices for 2004 and 2005. These are again the prices discussed above in the retail market section that were the results of the state bidding and auction procurement programs, as shown in Figure 8. In 2004, the lowest weighted-average bidding or auction price was in DC ($58.27) and the highest was in New Jersey ($65.84). There was a markup from the wholesale price in 2004 of 31 percent for the lowest bid/auction price and 48 percent for the highest 2004 bid/auction price. For 2005, the lowest weighted-average price was in Maryland ($98.65) and the highest were in DC and Pennsylvania[20] (both were $110.19). The markup ranged from 55 percent to 74 percent in 2005. Thus, not only was there a considerable increase in the bid/auction prices from 2004 to 2005, but also the proportional markup of the bid/auction prices above PJM wholesale prices was much greater. All the bidding/auction prices were higher than the highest monthly weighted-average prices of $86/MWh in August 2005. A possible contributing factor to this increased markup may be the increased volatility in the

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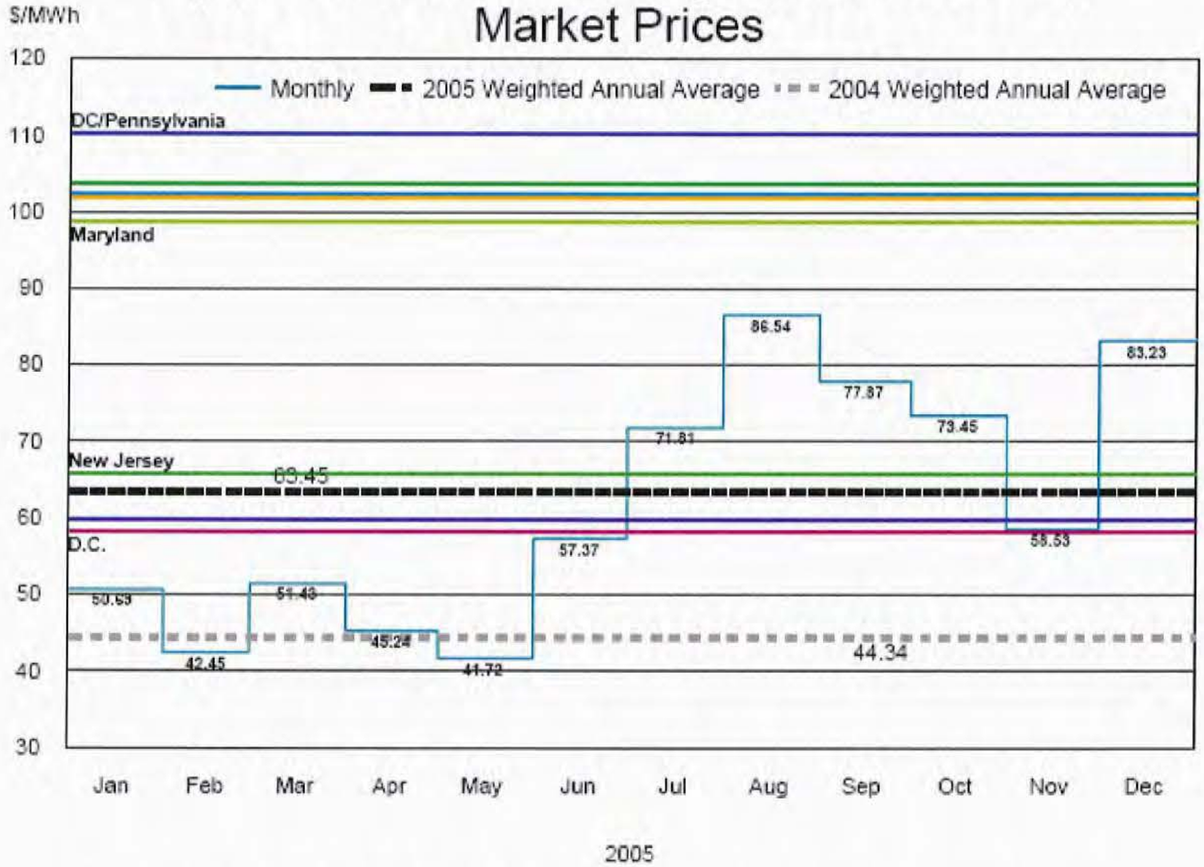
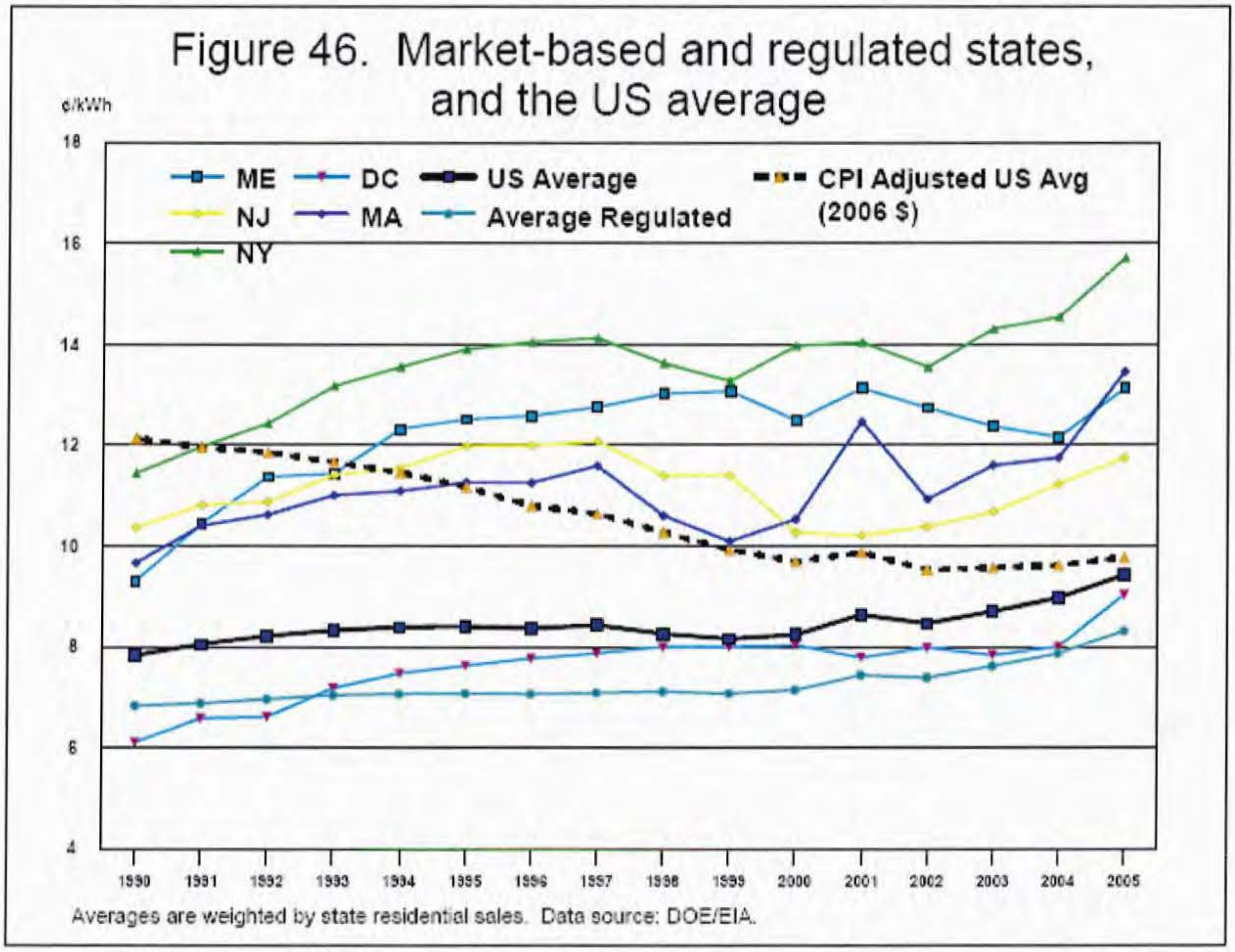
[20]Pike County Light & Power is in Pennsylvania, but is in the New York ISO wholesale market, not PJM. Prices generally are higher in the New York ISO than PJM (see the wholesale market section of this report).

wholesale markets. The timing and extent of this variability was discussed in more detail in the wholesale market section of this report.

Figure 45. Auction/Bidding Results and PJM Market Prices



To compare states that restructured with those that did not, it first has to be decided which states to compare. States are at various stages of transition to retail access (see the Appendix to this report for details on the timing of retail access and the transition periods). Figure 46 shows the price trends for the states where the transition period has ended for most customers in the state by 2005 and where the price residential customers are paying is based on a market process (that is, procurement of power for most residential customers in the state is through bidding, auction, distribution company purchase in the wholesale market, or some other process that secures power for customers that have not selected a supplier). Four states, Massachusetts, Maine, New Jersey, and New York plus the District of Columbia fit that specification and are placed in the figure. These are the same prices that were shown and described above in the regional sections on retail markets. Also depicted is the U.S. average prices for residential customers and the U.S. average price adjusted to 2006 dollars using the Consumer Price Index (CPI).[21] Each of the individual state trends and comparison to the U.S. average price are discussed above. Added to Figure 46 also is a weighted-average price of the 30 states that remain regulated.[22]



[21] The CPI is published by the U.S. Department of Labor, Bureau of Labor Statistics.

[22] These states are, Alabama, Arkansas, Colorado, Florida, Georgia, Iowa, Idaho, Indiana, Kansas, Kentucky, Louisiana, Minnesota, Missouri, Mississippi, North Carolina, North Dakota, Nebraska, New Mexico, Nevada (for residential), Oklahoma, Oregon (for residential), South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington,

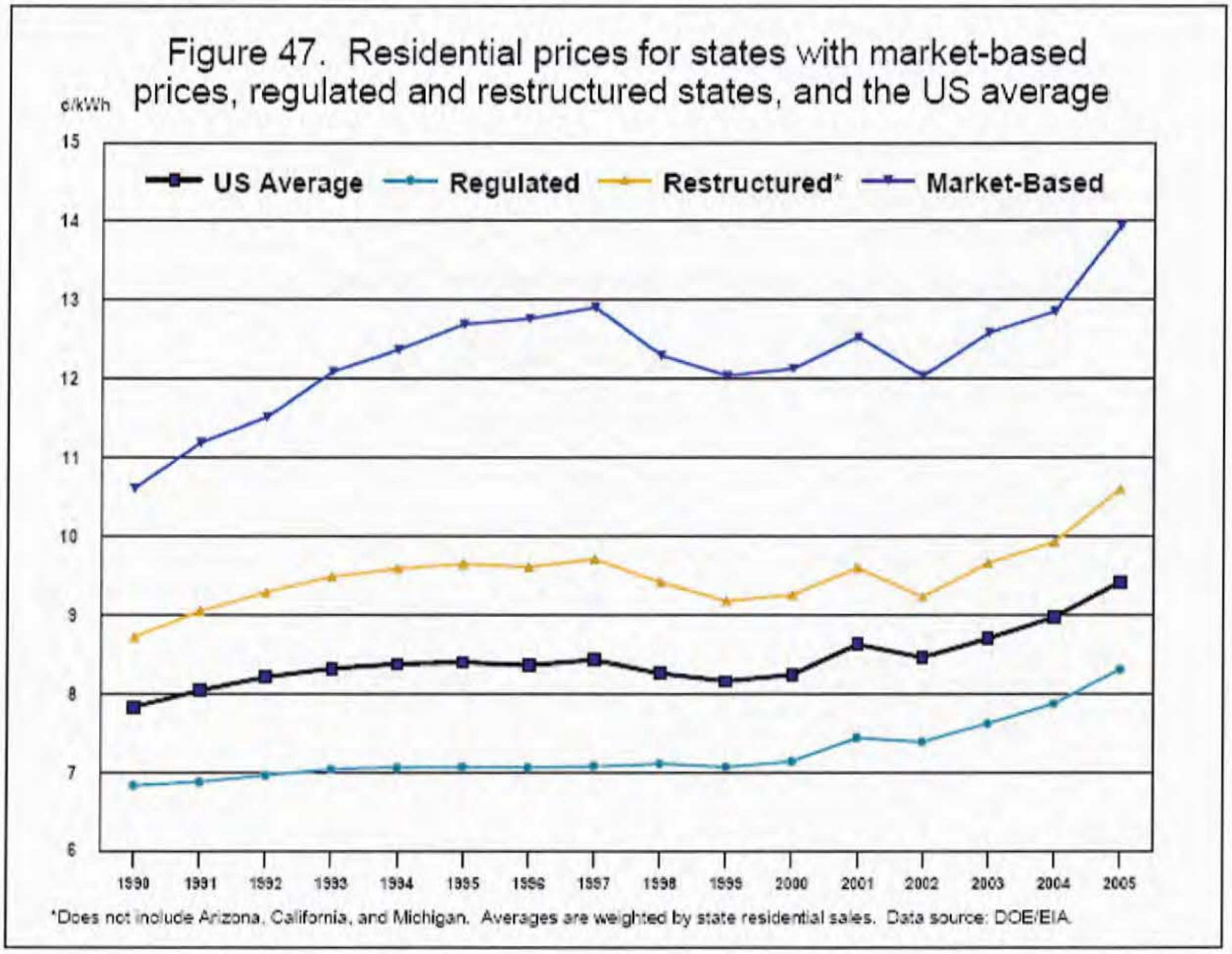
Most of these trend lines show increasing prices in the last few years, except the U.S. average adjusted for inflation – which shows the price adjusted for inflation was falling through the 1990s and has been relatively flat since 2000. The regulated states' prices are moving at about the same rate as the U.S. average between 2002 and 2005. The national average price increased by 11.3 percent and the weighted-average price for regulated states increased by 12.3 percent and the slope of the linear regression line for that period is nearly identical, at 0.31 for the national average and 0.30 for the regulated state average. The individual restructured states shown in the figure, except for Maine, increased at a faster rate from 2002 to 2005 than the national average. New Jersey, New York and D.C. were only slightly higher than the national average at 13 percent, 16 percent, and 13 percent respectively. Massachusetts increased by 23 percent during that period.

A combined weighted-average price was calculated for the individual restructured states shown in Figure 46 and a weighted-average of all states that restructured.[23] This is shown together with the U.S. average and the weighted-average of the regulated states in Figure 47. Both of the prices for the weighted-average restructured states and the weighted-average of the states where the residential customers are now paying market-determined prices increased more (at 14.9 percent and 15.8 percent, respectively) than the U.S. average and the weighted-average of the regulated states, again for the 2002 to 2005 timeframe. The slope of the linear regression line for that period is steeper at 0.44 for all restructured states and 0.60 for the states where the price caps expired. Since many of the states in the restructured group still have some form of price controls, the states where the price controls ended is a better indicator of residential customer pricing under the current restructuring arrangement in those states.

It should be noted that this analysis does not include the impact of the substantial price increases that occurred in 2006, as discussed in the retail market section.

Wisconsin, West Virginia, and Wyoming.

[23]The states included in this group of restructured states are, Connecticut, D.C., Delaware, Illinois, Massachusetts, Maryland, Maine, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Excluded are California, which suspended its retail access, and Arizona and Michigan, which continue to control utility generation cost.



In most restructured states, the electric utilities either transferred generation assets to an affiliate of the utility or the utility's assets were sold to an unaffiliated company. From DOE/EIA data,[24] in 1993, 34 states had over 90 percent of the electricity produced by utilities, while only one state had less than 50 percent of its generation produced from utility sources. As recently as 1997, only two states had less than 50 percent utility produced generation. By 2002, this picture had changed dramatically, when 14 states had less than 41 percent of electricity produced by utilities -- all of these states were states that restructured their electric utilities. Eight of these states had less than three percent of electricity produced by utilities. The utility share of state generation

[24]U.S. Department of Energy, Energy Information Administration, State Electricity Profiles 2002.

in 1993 and 2002 is shown in Table 2 for the states where the transition periods ended for most residential customers in 2006 or earlier.[25]

Table 2. Utility Share of Generation in States Where the Residential Price is Determined in the Market

	Utility Share of Generation - 1993*	Utility Share of Generation - 2002*
Delaware	92.1	2.8
District of Columbia	100.0	0.0
Maine	51.7	0.0
Maryland	96.7	0.1
Massachusetts	76.0	2.8
New Jersey	70.9	2.5
New York	85.6	31.1

*Electric utility share of total electricity generation in the state (MWh). Source: DOE/EIA.

While requiring or allowing utilities to sell or transfer generation assets may have appeared to be a good idea at the time it occurred,[26] in retrospect, this development greatly reduced state options for finding a solution to the current market developments, and makes a return to a traditional form of regulation nearly impossible in the short run.

In states where the transition period has ended and the generation portion of the customers' bills have been determined by the market, prices have increased faster than the national average and in states that did not restructure. Non-restructured states and some restructured states still in a transition period generally have increased about the

[25] This adds Delaware and Maryland that ended transition periods in 2006 for most customers to the five states examined above.

[26] Some believed that transferring the assets would reduce the chance that the utility would discriminate against and limit access for competing suppliers to reach retail customers.

same as the national average. It should be noted too that most non-restructured states remain at prices below the national average.

The evidence suggests that, at least so far, no discernable benefit can be seen for customers in restructured states once the rate caps have expired. Increasingly the evidence is beginning to now suggest that prices for customers in restructured states may actually be increasing faster than for customers in states that did not restructure.

The Wholesale Market

Figures 30 through 33 of the PJM real-time hourly prices in 2005 show the relative volatility in the hourly prices through the year, and in particular the second half of the year. The monthly weighted average prices were relatively flat through May, then began to climb in June. The increased volatility beginning in June was related to warmer weather and the resulting increased load. This increased volatility can be seen in nearly every region of the country, as the regional wholesale market prices in the figures in the wholesale section of this report also show.

A factor that is often mentioned as having a strong influence on electricity prices is the price for natural gas. The figures above also show that correlation. However, the hourly power prices and the price for natural gas are not always perfectly correlated. As can be seen in Figure 31, the volatility in PJM electricity prices began *before* the big jump in natural gas prices, which started in September and continued through the year. Also, the monthly weighted average price actually began to *fall* through November. This suggests that weather was more of a factor than natural gas prices during the early summer (when load increases) and fall (when load decreases). Natural gas prices impact electricity prices, but other factors are involved as well.

Clearly, one of those other factors is the frequency that the market price is being determined on the vertical portion of the supply curve. When the wholesale market price is set in this area, during peak hours, the price can climb quickly and to hundreds of dollars per MWh. The PJM market prices can be seen in the hourly price peaks in Figure 33. During peak hours, the demand for electricity increases to a point where the highest priced generation units may be needed to operate to meet the demand. For those hours, the price for all power is set by the highest priced marginal generation units, often units that use natural gas. The PJM Market Monitoring Unit's 2005 State of the Market Report, states that combustion turbine (CT) generation was the marginal unit 23 percent of the time during 2005. This figure does not include gas-fired combined-cycle generation, which would include most new units added to PJM in recent years and other marginal steam generation units. Therefore, for over 2,000 hours of the year CT units are determining the price. This has an impact on the overall wholesale price and eventually, on retail customers.

The price increases in the mid-Atlantic auctions have also been attributed to increasing natural gas prices. Since generation units that use natural gas are often on the margin, the bid price (not cost) for these units set the market price for that location. However, it should be noted that while natural gas units were 27.5 percent of PJM's installed capacity at the end of 2005, natural gas generated only 5.9 percent of the total generation in 2005 in PJM. *Over 90 percent of the generation during 2005 was from coal and nuclear units.* This underscores the impact of the marginal-bid price determining the market price and its impact on price that retail customers eventually pay.

The state auctions to secure supply for retail customers are interrelated with the wholesale market since suppliers and other market participants operate in or observe both the wholesale markets and the auctions for procuring retail supply. The prices that the consumers pay, therefore, is affected by the marginal price of power in the region and the frequency that the price is set in the vertical portion of the supply curve.[27] Ideally, in an efficient competitive market, this is what is needed to send the correct economic signal to consumers and suppliers to use and supply power efficiently.

However, the power industry is not like most competitive markets, since power supply typically has a long flat region of the supply curve that extends over most of the output range, and then turns upward and becomes nearly vertical as the maximum output is approached. This is sometimes described as a "hockey stick" shape, except, the way the supply curve is typically drawn, the handle and the head (the part that hits the puck) are about the same length. This is distinguished from the smooth upward

[27] In contrast, under traditional regulation, customers paid the average cost of power produced or purchased by their utility.

sloping supply curve usually found in economics textbooks. It is that vertical segment of the supply curve that is determining the price at many hours of the year. For consumers, this means that either an increase in demand or a decrease in supply will produce a disproportionately much larger increase in the market price.

Market Competitiveness

Electric market characteristics suggest that the market structure is not a robustly competitive one, as was hoped when restructuring began. Because of high supplier market concentration, the difficulty of entry from other firms to build new generation, limited entry from outside the area due to transmission access constraints, and existing market rules, the structure that is emerging more closely resembles that of an oligopoly, where there are only a few firms supplying all or most of the output, than a truly competitive marketplace. There is also an inelastic demand for electricity, particularly in the short-run, since customers have few practical substitutes. All these factors suggest the possibility that market conditions permit suppliers to exercise significant market power. These market structure issues were discussed at length in last year's Market Performance Review.

The frequency with which the price is determined in the vertical portion of the supply curve, as just described, also contributes to the suppliers' ability to influence the price and exercise market power. Specifically, by withholding some capacity, the supply curve is shifted to the left, meaning the vertical portion of the supply curve is reached at a lower quantity. Suppliers can also bid a very high price for a small portion of their capacity, so when demand is high and the higher priced capacity is selected for dispatch, it will set the price for all the capacity in the area. For consumers this means that higher prices are likely to result than what would occur with a more competitive structure, that is, a structure that permitted only limited ability to exercise market power.[28]

Coordinated interaction and tacit collusion among suppliers also could have particular relevance for electricity markets. The nearly continuous interaction that suppliers have in RTO markets can allow firms to excise market power and utilize anti-

[28]Market power is usually defined as the ability of a firm or group of firms to raise and maintain the product price significantly above a competitive level.

competitive bidding strategies. While transparency is important for markets to perform well, it can have the unintended result of creating markets that facilitate collusive supplier behavior. A lack of publicly available information impairs the ability to more fully assess market behavior.

There are academic papers that suggest that anti-competitive bidding strategies could happen and how it could (and perhaps actually does) happen in LMP markets like PJM.[29] While academics have been studying this issue for a few years, it is not purely an academic exercise. The 2000-2001 western power crisis demonstrated that it can and does happen. Given the fact that such strategies have been shown to be possible and successful, it is likely that suppliers are currently using strategic bidding techniques and withholding strategies to raise the price, strategies that would be less effective in a more competitive market. These strategies are particularly effective during periods of relatively high demand. In general, RTO market monitors and FERC do not examine markets for possible coordinated interaction and tacit collusion or the impact on market prices.

The price that retail customers receive, either directly from suppliers they choose or from a standard offer that is set by bidding or auction, will generally reflect what is occurring in the wholesale market. Any structural or market design flaw or significant supplier market power, will impact the resulting prices. The design and monitoring of the wholesale markets, however, is usually beyond state jurisdiction. Any required improvement in the market structure will have to be investigated and decided on by FERC.

As noted, the current wholesale market structure cannot be characterized as completely competitive. Suppliers can and do exercise an appreciable level of market power, particularly during periods of relatively high demand. This is a function of the existing market rules, supplier concentration, transmission access constraints, and other structural elements that were discussed above. Many of these can be changed through policy changes at the federal level. Others are structural and an intrinsic part of the

[29]HyungSeon Oh, Robert J. Thomas, Bernard C. Leiseutre, Timothy D. Mount, "A Method for Classifying Offer Strategies Observed in an Electricity Market," Elsevier, July 2004.

electric supply industry. Barring a significant technological breakthrough, appropriate public policy has to be shaped to fit these structural characteristics, and not be based on what works in other industries or on notions of what should work in theory.

Appendix: Summary of State Restructuring Activity

State	Investor-owned utilities/distribution companies	Restructuring legislation	Discounts
	Updates of Interest		
Arizona	Arizona Public Service Company (APS) and Tucson Electric Power Company (TEP)	Restructuring legislation passed in 1998. Retail access began January 1, 2001.	
	In 2002, the Arizona Corporation Commission (ACC) eliminated the requirement that utilities divest generation assets and that all power needed for standard offer service be purchased in the market. In an April 2005 Order, the ACC authorized APS to place generation assets into rate base. Retail access is allowed, however, rates were determined in a way that more closely resembles traditional regulation. Arizona's retail market was just beginning in January 2001 when the western power crisis was about at its peak. The interest that competitive suppliers had at the beginning disappeared and there are currently no shopping customers in the state, except large industrial customers on special contracts.		
California	Pacific Gas and Electric Company, Southern California Edison, San Diego Gas and Electric	Restructuring law passed in 1996. Retail access began April 1998.	Restructuring legislation required a 10% rate cut.
	In September 2001 retail access is suspended by the PUC.		
Connecticut	Connecticut Light & Power and United Illuminating	Restructuring law passed in 1998, revised June 2003.	Legislative discount: 10% below the 1996 rates, same rates in effect in 1999.
	Original Standard Offer service set to run from January 1, 2000 through December 31, 2003, for residential and small business customers. Revised restructuring law created the "Transitional Standard Offer Period," in effect from January 1, 2004 through December 31, 2006 – ended 10% rate reduction.		

Delaware	Delmarva Power & Light Co. (Conectiv Power Delivery) and Delaware Electric Cooperative (DEC)	Restructuring law passed March 1999. Retail access phased-in beginning October 1, 1999 for large Conectiv customers and ended April 1, 2001 when all customers were eligible. Rate freeze extended to March 2006 as part of merger of PEPCO and Connective and March 2005 for DEC.	Residential rate cut of 7.5% for Conectiv customers and a rate freeze for Delaware Electric Cooperative customers.
	Rate caps ended for Delmarva Power & Light Co. customers on May 1, 2006, were originally set to end September 2003, but were extended by merger resolution. Rate caps ended on March 31, 2005, for Delaware Electric Cooperative customers. In March 2005, the Commission approved Delmarva Power & Light Company as the Standard Offer Service supplier for after May 1, 2006 – customer prices are determined by a competitive bidding (RFP) process and in the wholesale market. See details in text.		
District of Columbia	Potomac Electric Power (PEPCO)	Restructuring legislation passed 1999. Retail access began January 1, 2001.	Commission in 1999 approved a reduction in PEPCO's residential rates by 7% between January 1, 2000 and February 7, 2001, and capped at the reduced levels through February 7, 2005. Electric rates for customers who participate in PEPCO's Residential Aid discount ("RAD") program are capped until February 2007.

	*PEPCO's distribution service rates are capped until August 2009 for RAD customers and until August 2007 for all other customers. PEPCO (which sold all its generation plants by January 2001) is required to procure wholesale generation through a competitive bidding solicitation that is overseen by the Commission.		
Illinois	Central Illinois Public Service Company (AmerenCIPS), Central Illinois Light Company (AmerenCILCO), Commonwealth Edison, Illinois Power Company (AmerenIP)	Restructuring law passed in 1997. Retail access phased-in, beginning October 1,1999, retail access for residential customers began on May 1, 2002. Transition period until January 2007.	15% in 1998 and an additional 5% for Commonwealth Edison and Illinois Power residential customers. Smaller discount for customers in other areas.
	The Illinois restructuring legislation's transition period ends on December 31, 2006. Illinois is currently planning to use an auction approach, similar to the New Jersey BGS auction, to procure power supply for customers beginning January 2007. The first auction is scheduled for September 2006.		
Maine	Bangor Hydro-Electric, Central Maine Power, Maine Public Service Company	Restructuring law passed in May 1997. Retail access began March 2000. All standard offer prices determined by a bidding process.	Rate Reductions from 2.5% to 15%
	See details in text on Maine Standard Offer prices.		
Maryland	Allegheny Power (APS), Baltimore Gas & Electric (BG&E), DPL/Connectiv (DPL), Potomac Electric Power Company (PEPCO)	Restructuring law passed in April 1999. Residential transition ends July 1, 2008 for Allegheny Power (APS) and July 1, 2006 for Baltimore Gas & Electric (BG&E). Transition ended July 1, 2004 for DPL/Connectiv (DPL) and July 1, 2004 for Potomac Electric Power Company (PEPCO).	APS: About 7% reduction for residential, BG&E: 6.5% reduction for residential, DPL/Connectiv: 7.5% reduction for residential, PEPCO: 3% reduction for residential.
	See details in text on Maryland.		

Massachusetts	Boston Edison, Cambridge Electric, Commonwealth Electric, Eastern Edison, Fitchburg Gas and Electric, Massachusetts Electric Company, Western Massachusetts Electric Company.	Restructuring law passed in November 1997. Retail access began March 1998. Transition until March 1, 2005.	Discount of 10% for all standard offer customers.
	Standard Offer Service (SOS) expired February 28, 2005. See Massachusetts section in text.		
Michigan	Alpena Power Company, American Electric Power Company, Edison Sault Electric Company, Detroit Edison Company, Consumers Energy Company	Restructuring law passed in June 2000. Retail access began January 1, 2002. Transition rate caps until January 2003 for industrial customers, January 2005 for commercial customers, and January 2006 for residential customers.	5% rate reduction through the end of 2005 for every residential electric customer of Detroit Edison Company and Consumers Energy Company.
	In December 2005, the Michigan PSC unbundled Consumers Energy and Detroit Edison's rate schedules to make it easier for customers to compare full service and choice service options. The PSC also found that it is unlikely that there will be any new stranded costs in the future.		
Montana	Montana Dakota Utilities, Energy West Montana, and Northwestern Energy	Restructuring law passed in 1997. Retail access began 1998 (for large customers). Transition period extended to July 1, 2027 for residential customers.	2 year rate freeze began July 1998.
	A 2003 law amended the state's restructuring law by extended the transition period to July 1, 2027 for residential customers and requires NorthWestern Energy to continue to be the supplier for small customers in central and western Montana. Mid-size and large customers continue to have retail access. NorthWestern Energy owns no generation capacity. Until 2027, large customers (average monthly demand equal to or greater than 5,000 kilowatts) who are not currently being served by		

	default supply must purchase electricity from the market. Medium customers (average monthly demand equal to or greater than 50 kilowatts but less than 5,000 kilowatts) may be served by default supply or choose an alternative supplier.— but total average monthly billing demand of medium customers that choose an alternative supplier in each calendar year may not exceed 20,000 kilowatts. Small customers may be served by default supply or may be served through a commission-approved small customer electricity supply program. The total average monthly billing demand of small customers who choose to be served through a small customer electricity supply program in any calendar year may not exceed 10,000 kilowatts. As of now, there are no commission-approved small customer electricity supply programs. NorthWestern Energy agreed to a seven-year power purchase agreement with PPL Montana, the state's largest power generator, for default supply for NorthWestern's 310,000 customers (announced July 2006). Typical residential electric bills are projected to increase by approximately 7 percent beginning July 1, 2007. The contract begins July 1, 2007 when PPL's current five-year contract with NorthWestern expires. PPL's current contract provides about 55 percent of the electricity for NorthWestern customers in Montana. The new contract initially will provide about 37 percent (325 Megawatts) of the power needed to supply NorthWestern customers, and then decline gradually over the seven years. The price paid to PPL for generation will be a 40 percent increase at the beginning, and increases another 3.5 percent to 2 percent in each for the next five years. The projected increase next year for residential consumers is 7 percent because the price increase paid to PPL is only a portion of customers' overall bill. The 7 percent projected increase could be higher or lower, depending on fluctuations in the regional electricity market NorthWestern still must buy nearly one-third of its power for Montana customers on the open market. FERC ruled in May 2006 that PPL does not have "market power" in Montana, and therefore can charge market-based prices. (Sources: Montana PSC staff, NorthWestern Energy, and Gazette State Bureau, "NorthWestern Energy to pay PPL 40% more for power.")		
New Hampshire	Public Service Company of New Hampshire (PSNH), Granite State Electric Company (GSEC), Unitil Energy	Original restructuring law passed in 1996. Retail access implementation was delayed by litigation. GSEC began retail access August 1998, PSNH began	10% rate reduction for PSNH residential customers.

	Systems, Inc. (UES), and New Hampshire Electric Cooperative, Inc. (NHEC).	May 2001, and UES companies began May 1, 2003.	
	*The Public Utilities Commission approved a proposal in November 2003 that encourages large commercial and industrial customers to switch from PSNH to electricity purchased from competitive suppliers. The Retail Energy Services, or RES program, was designed for customers whose billing demand is one megawatt or greater. If they agree to join, such customers may choose a supplier and receive a per-kilowatt-hour credit against the energy portion of their electric bills. It is hoped that this credit will provide incentive to a customer to switch to a competitive supplier. Currently, the transition service price is lower than the market price for electricity, so there is no incentive for customers to switch. The RES program is designed to encourage comparison shopping. It went into effect on February 2004 and will end after two years. Most residential customers receive Transition Service.		
New Jersey	Connectiv, GPU/ FirstEnergy Company - Jersey Central Power & Light, PSE&G, Rockland	Restructuring law passed in February 1999. Retail access began August 1999. Transition ended August 2003.	5% in 1999 and an additional 10% over the next 3 years.
	See New Jersey summary in text for BGS auction results. FERC approved Exelon/PSEG merger in July 2005 – other agency decisions are still pending (including the NJBPU).		
New York	Central Hudson, Consolidated Edison, New York State Electric and Gas, Niagara Mohawk Power Company, Orange & Rockland Utilities, Rochester Gas and Electric	Restructuring implemented by Commission orders, no restructuring law passed. Retail access and transition periods differ by company. See below.	Discounts differed by company. See below.
	*The New York State Public Service Commission (PSC) initiated deregulation discussions with each investor-owned utility individually. The PSC approved utility restructuring plans that dealt with rate levels, retail competition, and corporate restructuring of all of New York's seven major electric utilities. The transition to competition began in 1998 for the utilities with approved plans. Each plan is different.		

From DOE "Status of State Electric Industry Restructuring Activity" 2003, NY State Public Service Commission, and Public Utility Law Project (PULP).[30]

Central Hudson Gas & Electric
Retail access began: September 1998
Rates frozen at 1993 levels until June 30, 2001
Full Retail Access - July 1, 2001
Sold power plants in 2000 and entered into long term buyback arrangements for most customer power needs, balance is purchased in the wholesale spot market. Major buyback contracts have expired and rates have risen.

Consolidated Edison
Retail access began: June 1, 1998
25% rate reduction for 5 years for large industrial, 10% for all other customers phased in over 5 years
Full Retail Access - December 2001
The New York PSC in May 2000 adopted the Market Supply Charge/Market Adjustment Charge (MSC/MAC) methodology to flow through NYISO prices with a monthly adjustment taking into account purchased power costs including "legacy" contracts and hedges. Prices are high and volatile. Con Ed has the highest residential rates in NY, over 60% higher than the next highest rates (Orange & Rockland Utilities).[31] Con Ed testified in the last rate case it plans to buy more than 40% of energy in the NYISO spot markets.[32]

Long Island Power Authority
January 2002: LIPA opened up the Long Island electricity market completely on January 17, 2002, seven years ahead of schedule. LIPA is no longer subject to PSC rate regulation. Data on retail migration is not available. Rates that were the highest in NY state under LILCO were reduced in the transition to public ownership and have increased since the advent of the NYISO and higher natural gas prices, but not to the extent that Con Ed rates have risen.

New York State Electric & Gas
Retail access began: August 1, 1998
Rates capped until 2003, after 2003, energy rates were fixed for 2-

[30] E-mail correspondence with Gerald Norlander, Executive Director of PULP
[31] http://www.pulp.tc/Residential_Electric_Rates_7-94_-1-06_LILCO.pdf
[32] http://www.pulp.tc/CE_WholesaleElectricSupply5-5-04.pdf

year periods. Also a 5% rate reduction for industrial and large commercial consumers for five years (five reductions of 5% each), and residential and small commercial/industrial consumers received 15% reduction by third year and 5% by the fifth year.
Full Retail Access - August 1,1999

NYSEG rates were frozen through 2002 and since then they have set a fixed rate every two years. The energy price is based on forecast wholesale energy market prices plus a 35% adder to cover purchasing related costs (about 17.5%) and to give "headroom" for retail competitors. In the past plan (2002-2005) the company over-earned (partially as a result of the "headroom" for retail competition which did not capture significant additional market share) and more than $100 million was returnable to ratepayers as shared earnings. A rate case decision on the next plan is expected in August 2006. The company seeks to continue its fixed rate default service, the PSC Staff argues to abolish it. Even with the "headroom" (which may come back in part as shared earnings) residential customers have had stable rates in comparison with NY utilities that incorporated more NYISO spot market purchase costs in their rates.

Niagara Mohawk Power/National Grid
Retail access began: September 1, 1998
Residential and commercial customers received a 3.2% phased in decrease over three years. Industrial received about a 13% phased in rate reduction. Rates for electricity and delivery were set until September 2001. Rate changes after that period must go through the PSC.
Full Retail Access - August 1, 1999
As part of merger agreement when National Grid bought Niagara Mohawk "calls for National Grid to lower electricity prices and freeze natural gas delivery rates for 10 years." Essentially increasing the transition to 2011. Rates were increased in a "reset" in 2005. The largest customers have prices linked to spot market prices, and gradually spot market prices will be introduced to smaller business customers.

Orange and Rockland Utilities
Retail access began May 1, 1998 O&R introduced a purchase of receivables program for competitive providers.
Rates fell by 4%, 4%, and 14% for residential, commercial and industrial respectively in 1995-1996. This was followed by two 1% reductions, in 1997 and 1998, for residential costumers and an 8.5% drop in 1997 for large industrial customers.
Full Retail Access - May 1, 1999 includes energy and

	capacity The New York PSC in May 2000 adopted the Market Supply Charge/Market Adjustment Charge (MSC/MAC) methodology to flow through NYISO prices with an adjustment for "legacy" contracts and hedges. O&R residential prices have increased and became volatile. **Rochester Gas & Electric** Retail access began July 1, 1998 Rates set until mid 2002, residential, commercial, and industrial consumers received 7.5%, 8%, and 11.2% rate reductions, respectively, to be phased in over five years. Full Retail Access - July 1, 2001, includes all customers, energy and capacity. Delivery charges are regulated by the PSC, energy prices are fixed annually based on wholesale energy market projections plus an adder to cover purchasing costs and "headroom" for retailers. Customers also have a variable rate option. Sold power plants and entered into long term buyback arrangements for most customer power needs, balance is purchased in the wholesale spot market. Comparatively unaffected by NYISO prices because legacy contracts still cover much of the capacity. **On August 25, 2004, the Commission adopted the Statement of Policy on Future Steps Toward Competition in Retail Energy Markets. The Policy Statement sets forth the Commission's goals and visions for the further development of robust retail energy competition in New York and provides a flexible framework for the Commission to analyze and respond to evolving market conditions and thereby to facilitate market development as required. Central Hudson's was approved May 2005.		
Ohio	AEP/Columbus Southern Power Company, AEP/Ohio Power Company, Cincinnati Gas & Electric Company, Dayton Power and Light Company (DP&L), First Energy/Cleveland Electric Illuminating Company, First Energy/Ohio Edison Company, First Energy/Toledo	Restructuring law passed in July 1999. Retail access began January 1, 2001. Original transition until December 31, 2005 and through Dec 2003 for DP&L – later extended to Dec 2005. Extended transition through Dec 2008 for AEP and FirstEnergy companies.	5% rate reduction on generation portion and 5 year rate freeze (was to end December 2005), except DP&L (3 year freeze, and 5% reduction, then in 2.5% reduction of generation costs starting in 2006

	Edison, Monongahela Power Company		and lasting 3 years). AEP extended 3 years (through 2008), allowed 3% increase per year. FirstEnergy Rates are frozen until 2008 except fuel and tax adjustments.
	The Public Utilities Commission of Ohio (PUCO), fearing that a competitive base had not yet been established that would ensure consumer safety, developed Rate stabilization plans in 2003. American Electric Power (AEP), FirstEnergy, Duke Energy Ohio (formerly Cincinnati Gas & Electric Company), and Dayton Power & Light (DP&L) all filed rate stabilization plans (RSP). Rate Stabilization Plans filed are as follows:[33] **AEP:** Three years: Jan 1, 2006-Dec 31, 2008 Generation rates will increase 3% per year for Columbus Southern Power customers and by 7 percent for Ohio Power customers. Distribution rate remain fixed through 2008. $14 million to be used for low-income assistance and economic development. Allows AEP to request additional rate increases for environmental and security expenses as needed. **Duke Energy Ohio:** Three years: Jan 1, 2006-Dec 31, 2008 for residential. Jan 1, 2005-Dec 31, 2006 for non-residential. Generation rates are allowed to increase. These increases can be avoided by 25% of residential consumers that shop for a competitive supplier. Distribution rates will increase by 4.4%. **DP&L:** Five years: Jan 1, 2006-Dec 31, 2010 Generation rate increase capped at 11% over the five year period. Residential customers will receive a 7.5 % discount on bills from 2006-2008. Distribution rates will remain fixed until 2008. If rates fall, PUCO can cancel RSP and order DP&L to use market based rates.		

[33] This information was obtained from the OCC site for Electric Choice and can be found at http://www.pickocc.org/electric/echoice.shtml.

FirstEnergy:
Three years: Jan 1, 2006-Dec 31, 2008
The Public Utilities Commission of Ohio (PUCO) adopted a Rate Stabilization Plan (RSP) for FirstEnergy that provided for a competitive bidding process, or auction, to be conducted on FirstEnergy's electric load to see if lower rates could be obtained. The auction was conducted in December 2004. The PUCO rejected the results of the auction, finding that the RSP provided lower electricity rates and the RPS rates were then used. The PUCO will hold additional auctions in the future to continue to test the market for lower generation rates.

FirstEnergy also agreed to a Rate Certainty Plan with the OCC and cities of Akron, Cleveland, and Toledo to continue to stabilize prices through 2008.

A second auction in early 2006 to supply 9,000 MW of power in 2007 and 2008 to FirstEnergy's customers was cancelled after no competitive supplier submitted applications to participate.

Transmission rates for all companies may vary during each utility's respective rate stabilization periods.

The Ohio Consumers' Counsel (OCC) filed suit against the PUCO in the Supreme Court of Ohio, claiming that the Rate Stabilization Plans (RSP) of AEP, FirstEnergy, Duke (formerly CG&E), DP&L violated state law. The OCC won the suite against AEP and FirstEnergy.[34] The Supreme Court of Ohio agreed with the OCC's case against FirstEnergy and AEP, remanding the RSPs to the PUCO. The case against Duke is still open. The case against DP&L is open, and only in the briefing stage.

On June 14, 2005, the PUCO directed Monongahela Power and AEP to pursue potential terms and conditions for transferring Monongahela Power's Ohio territory to AEP. In August 2005, Allegheny Power (the delivery company of Allegheny Energy that includes Monongahela Power) announced an agreement to sell its Ohio service territory's transmission and distribution assets to American Electric Power's Columbus Southern Power subsidiary for net cash proceeds of approximately $55 million. The PUCO approved the transfer of Monongahela Power's service territory to AEP on Nov. 9, 2005.

[34] http://www.pickocc.org/news/2006/07052006.shtml
[35] http://www.pickocc.org/news/2006/05102006.shtml

	The Supreme Court of Ohio also found that deferring transmission charges to a later date by FirstEnergy and DP&L was in violation of the rate cap.[35] *Most retail activity has been in the northern part of the state (the area served by the FirstEnergy companies). That area has historically had higher prices in the state. Most residential switching customers have used the Community Choice aggregation option available through the state. The rest of the state has shown almost no movement of residential customers. *Though Dayton Power and Light Co (DP&L) was to start charging market prices for power in January 1, 2004, fears of volatile rates caused certain public-interest groups to make a deal with the company, freezing distribution rates through 2008. The plan will allow DP&L to file for rate increases in 2006 to pay for higher costs.		
Pennsylvania	Allegheny Power, Duquesne Light, Metropolitan Edison, PECO Energy, Pennsylvania Energy, Pennsylvania Power, Pennsylvania Power and Light, UGI Utilities	Restructuring law passed in December 1996. Retail access phased in beginning January 1999 and reached all customers by January 2001.	No required reductions in legislation, some companies had them in first year and phased out over three years.
	*New regulations proposed December 2004 requires default suppliers for small retail customers to offer at least 1 year contracts at fixed rates and obtain their power through competitive bids. These rules apply to "last resort" suppliers – those which supply power to customers who can't or don't choose to receive power through alternative suppliers. Current default rates are capped as a result of the restructuring related to the Electric Choice Law. The intent of these new regulations is to maintain service availability at reasonable terms even after the rate caps expire. Duquesne prices are open, and set by the market.		
Rhode Island	Narragansett Electric	Restructuring law passed in August 1996. Retail access phased-in beginning July 1997. 2002 legislation requires utilities to offer Standard Offer Service until January 2009.	7% reduction.

Texas	Central Power and Light, Reliant Energy, TXU Electric and Gas, TXU SESCO, Texas-New Mexico Power Company, West Texas Utilities	Restructuring law passed in June 1999. Retail access began January 2002. Transition is at least 3 years or until 40% of the power consumed within their certified service areas is provided by competitors.	Rates frozen at September 1999 levels. A bundled rate 6% less than its affiliated transmission and distribution utility rates for its residential and small commercial customers.
	See Texas update in text. *Entergy, the major provider of energy in Southeast Texas, announced in June 2004 that it has halted current efforts to move to retail open access in Southeast Texas. PUCT denied Entergy's application to create an independent organization to manage the Entergy transmission system in Texas. Entergy was also told to terminate its current pilot program and delay retail open access until a FERC approved RTO or some other independent entity certified by Texas law is in place. The company was asked to explore joining the Southwest Power Pool RTO as an alternative. Affiliated retail electric providers are required to sell electricity at the price to beat until January 2007.		
Virginia		Restructuring law passed in March 1999. Retail access began January 2002. Transition extended until 2010.	
	See section on the status of competition in the Commonwealth.		

Sources: * indicates source as:
http://www.eere.energy.gov/femp/program/utility/utilityman_staterestruc.cfm other information from corresponding state public utility commissions or others sources as indicated.